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Technical Support for PSD Permit Modification Application

Natural Gas Boiler Project

PREPARED FOR:

SOLVAY SODA ASH JV

PROJECT NO. 170-12-2
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LIST OF ABBREVIATIONS AND ACRONYMS

ACFM	Actual Cubic Feet per Minute
AMS	American Meteorological Society
AQRV	Air Quality Related Value
ASL	Above Sea Level
ATSDR	Agency for Toxic Substances and Disease Registry
AQCR	Air Quality Control Region
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
BLM	Bureau of Land Management
BOOS	Burners Out of Service
BPIP	Building Profile Input Program
CA-BACT	California Best Available Control Technology Clearinghouse
CAM	Compliance Assurance Monitoring
CATC	Clean Air Technology Center
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
COMS	Continuous Opacity Monitoring System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DEM	Digital Elevation Model
dscf	Dry Standard Cubic Foot
EDMS	Emissions Data Management System
EA	Environmental Assessment
EPA	United States Environmental Protection Agency
eq	Equivalent
ETO	External Thermal Oxidation
ESP	Dry Electrostatic Precipitator
°F	Degrees Fahrenheit
FGR	Flue Gas Recirculation
FLAG	Federal Land Managers Air Quality Related Values Workgroup
FLM	Federal Land Manager
FR	Fuel Reburn
FWS	United States Fish and Wildlife Service
ft	Feet
g	Gram
GCP	Good Combustion Practices
GED	Good Engineering Design
GHG	Greenhouse Gas
GIS	Geographical Information Systems
gr	Grain (mass)
H2H	Highest Second-Highest
H4H	Highest Fourth-Highest
H_2S	Hydrogen Sulfide
H_2O	Water
H_2SO_4	Sulfuric Acid Mist
HAP	Hazardous Air Pollutant
HF	Hydrogen Fluoride
HNO_3	Nitric Acid

hr	Hour
IRIS	Integrated Risk Information System
IUR	Inhalation Unit Risk
IWAQM	Interagency Workgroup on Air Quality Modeling
K	Kelvin
l	Liter
lb	Pound
LEA	Low Excess Air
LNB	Low-NO_X Burner
m	Meter
min	Minute
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MMscf	Million Standard Cubic Feet
µ	Micro (10^{-6})
NAAQS	National Ambient Air Quality Standards
NLCD	National Land Cover Database
NRCS	National Resources Conservation Service
NED	National Elevation Dataset
NESHAP	National Emission Standards for Hazardous Air Pollutants
NP	National Park
NPS	National Park Service
NSR	New Source Review
N_2	Nitrogen
NH_3	Ammonia
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrate
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NWS	National Weather Service
O_2	Oxygen
O_3	Ozone
OC	Oxidation Catalyst
OEC	Oxygen-Enhanced Combustion
OFA	Overfire Air
OLM	Ozone Limiting Method
PAE	Projected Actual Emissions
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter (with aerodynamic diameter ≤ 2.5 micron)
PM_{10}	Particulate Matter (with aerodynamic diameter ≤ 10 micron)
ppb	Parts per Billion
ppm	Parts per Million
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
PVMRM	Plume Volume Molar Ratio Method
RBLC	RACT/BACT/LAER Clearinghouse
RCO	Regenerative Catalytic Oxidizer
RTO	Regenerative Thermal Oxidizer
s	Second
SA	Soda Ash

scf	Standard Cubic Foot
$SCONO_x$™	Non-selective Catalytic Reduction
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SMU	Soil Map Unit
SNCR	Selective Non-Catalytic Reduction
Solvay	Solvay Soda Ash Joint Venture
SO_2	Sulfur Dioxide
SO_4	Sulfate
TDS	Total Dissolved Solids
tph	Tons per Hour
tpy	Tons per Year
TWSA	Toxicity-weighted Screening Analysis
ULNB	Ultra-low NO_x Burner
USDA	United States Department of Agriculture
USFS	U.S. Forest Service
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound
WAAQS	Wyoming Ambient Air Quality Standards
WAQSR	Wyoming Air Quality Standards and Regulations
WDEQ	Wyoming Department of Environmental Quality
WESP	Wet Electrostatic Precipitator
WRAP	Western Regional Air Partnership
wscf	Wet Standard Cubic Foot
yr	Year

1.0 INTRODUCTION

Solvay Soda Ash Joint Venture (Solvay) proposes to install one 254 MMBtu/hr natural gas-fired package boiler (new boiler) to provide steam and heat to the facility's production processes and for other purposes such as building heat. Currently, steam and heat are provided to the facility by two coal-fired boilers (Sources #18 and #19) which are routinely shut down for maintenance and thus are not operated at full annual capacity. As a result, production at the facility is also limited (i.e., bottlenecked) when steam is not available from the existing boilers to support production processes. With the addition of the gas-fired boiler, additional steam will be available to the facility to supplement or replace steam from the existing boilers. Solvay proposes to also install a clear liquor heat exchanger and make other minor operational and equipment changes to debottleneck production in other ways. As a result, several sources will be debottlenecked, allowing an increase in annual production at the facility. None of the short-term (hourly and 24-hour) existing process source capacities will change with this boiler addition. The combination of changes will serve to increase both short-term and long-term production while remaining within the previously permitted capacity rates and, aside from the new boiler, remaining within both short-term and long-term potential-to-emit limits.

The actual emissions changes from the new boiler, associated debottlenecked sources, and creditable contemporaneous emissions increases and decreases result in a significant net actual emissions increase of particulate matter (PM, PM_{10}, and $PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG), thus triggering Prevention of Significant Deterioration (PSD) review. This report provides a review and technical analysis of the various requirements triggered by PSD rules as part of an application for permit modification. This technical analysis consists of a facility and project description (Section 2.0), followed by a PSD applicability analysis (Section 3.0), a regulatory applicability review (Section 4.0), a Best Available Control Technology (BACT) review for criteria pollutants (Section 5.0), a Best Available Control Technology (BACT) review for GHG (Section 6.0), and air quality impact analyses for both Class II and Class I areas (Sections 7.0 and 8.0). In addition, a PSD additional impacts analysis for growth, soil and vegetation impacts is provided in Section 9.0, a qualitative ozone analysis is provided in Section 10.0, and an inhalation risk assessment for hazardous air pollutants (HAPs) is provided in Section 11.0.

The Solvay facility is located in Section 31, T18N, R109W, approximately 20 miles west of the town of Green River, in Sweetwater County, Wyoming. The Universal Transverse Mercator (UTM) location is 603.7 km Easting and 4594.8 km Northing (North American Datum 1927, Zone 12). The geographic coordinates are 41.502 N degrees latitude and 109.757 W degrees longitude. The facility location on a regional scale map is shown in Figure 1-1; a westerly view of the facility is shown on Figure 1-2.

Figure 1-1. Solvay Facility Location on a Regional Scale Map

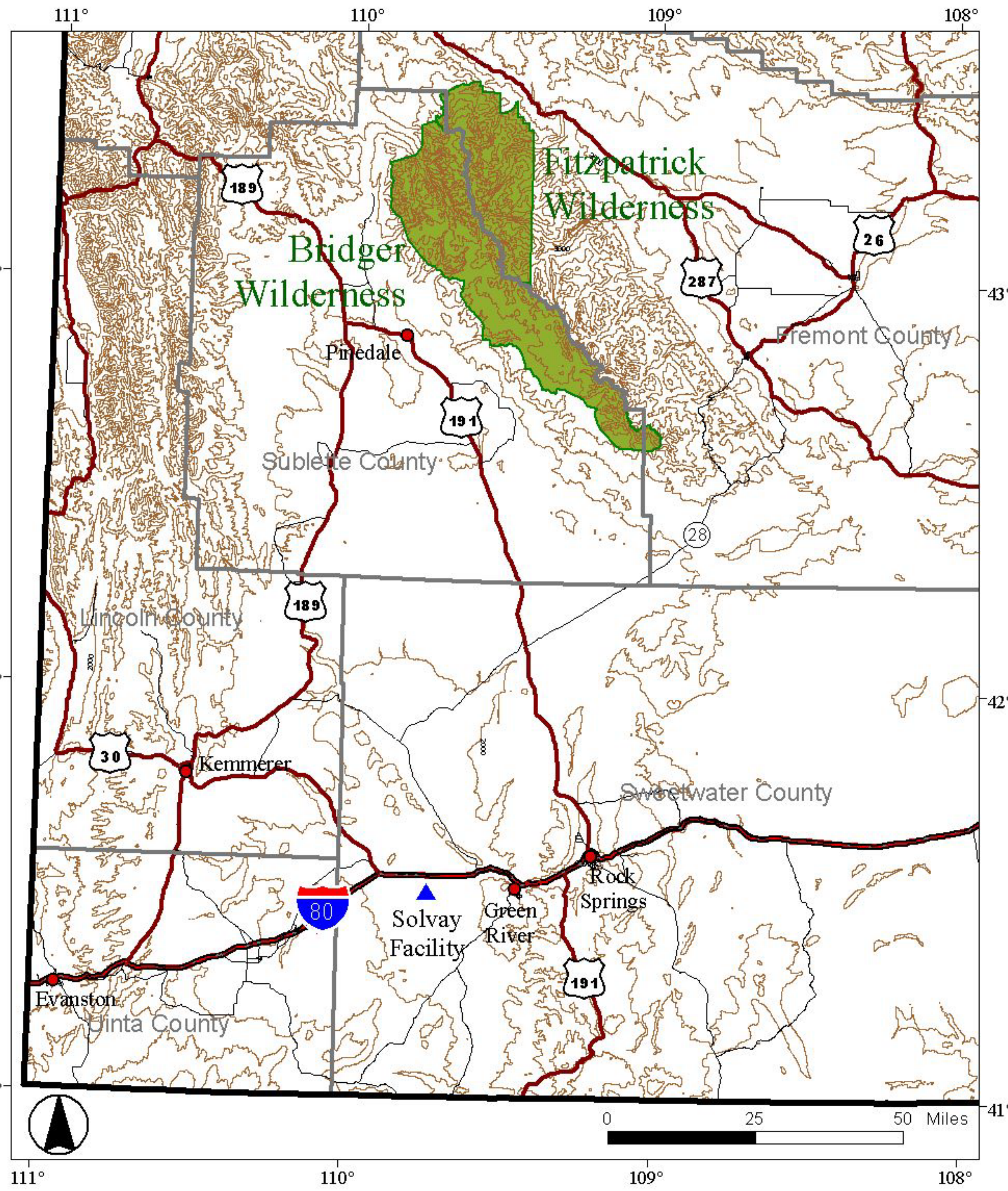

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Figure 1-2. Westerly View of Solvay Facility

2.0 FACILITY AND PROJECT DESCRIPTION

The Solvay facility is an existing underground trona mine with surface processing facilities. The trona ore (sodium sesquicarbonate dihydrate [$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$]) is processed into sodium-based products, including soda ash (sodium carbonate [Na_2CO_3]), Alkaten (animal feed), T-200 (air pollution control), sodium sulfite, and sodium bicarbonate. Construction of the facility began in 1979, and it became operational in 1982. Operations at the facility include the use of crushers, screeners, rotary calciners, rotary dyers, separation and recrystallization equipment, enclosed bulk storage, product loading/material handling equipment, boilers, and coal handling facilities. The air emission sources consist principally of calciners, dryers, boilers, and material handling processes. The facility is presently permitted under Wyoming Department of Environmental Quality (WDEQ) Operating Permit No. 3-0-126-1 (effective February 28, 2006) and an operating permit renewal, WDEQ Operating Permit No. 3-1-126 (currently draft) will replace permit No. 3-0-126-1.

This application is for the installation of a 254 MMBtu/hr natural gas-fired package boiler to provide additional steam/heat to the facility's production processes, supplementing two existing coal-fueled boilers. The proposed steam package boiler was manufactured by Foster Wheeler (model AG-5195) and was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers, increasing steam plant production capacity by 33 percent. As part of the 2003 purchase of the American Soda plant, Solvay owns this boiler. The Foster Wheeler boiler specifications are provided in Appendix A: .

The criteria pollutant BACT analysis (Section 5.0) for the additional boiler concludes that an ultra-low NO_X burner (ULNB) with associated 30 percent flue gas recirculation (FGR) and combustion control instrumentation will be required to minimize NO_X and CO emissions with a guarantee of 9 ppm NO_X and 50 ppm CO (see Appendix B: , Coen Burner bid). Because the package boiler burner will be upgraded to meet these emission levels, additional information has been provided by the burner manufacturer, Coen, regarding source release parameters (e.g., exhaust airflow, exhaust temperature, etc.) for the package boiler with its new burner configuration (see Appendix B: , Page 1).

Currently, the Solvay plant cannot reach its capacity soda ash (SA) production. Primary reasons are that the crystallization processes are too slow and that there is insufficient steam available from the two existing boilers (Sources #18 and #19). The steam limitation is due at least in part to the frequency and length of time the existing boilers are shut down for maintenance. When the existing boilers are shut down and are not providing steam, the SA production circuits at the facility are also reduced or shut down, resulting in a loss of annual SA production. With the addition of the gas-fired package boiler, additional steam will be available to the facility at all times, and Solvay will have flexibility to shut any one of the three boilers down for maintenance without substantial curtailing of SA production. Solvay will also gain some flexibility in its boiler fuel consumption, between coal and natural gas so that it can take advantage of the lower-cost fuel. This permit modification assumes no SA production limitation on combined steam production and the additional boiler is to be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their maximum while the gas boiler would supplement the steam demand. The additional steam will allow several other emission units at the facility to operate at higher rates and more hours each year (i.e., these sources will be debottlenecked), resulting in the actual increases in annual production at the facility. None of the debottlenecked emission units will operate above current permitted capacities.

The new heat exchanger will be a clear liquor preheater which will use steam heat to increase the temperature of the clear liquor (with product in solution) upstream of the crystallizers which will increase the evaporation rates and speed of crystallization allowing short-term actual production to come nearer to permitted capacity. With the installation of the package boiler and new heat exchanger, Solvay anticipates the debottlenecking to increase soda ash production by approximately 360,000 tons per year from the current actual production level of 2.55 million tons to 2.91 million tons of soda ash.

None of the existing emission units will be physically modified, and will be capable of accommodating the anticipated increases in annual production. In other words, the debottlenecking of the existing emission units will not result in any short or long-term PTE emissions increases, but it will allow the facility to produce more product and operate more hours each year, resulting in annual actual emissions increases. The details on emissions increases associated with the project are provided in Section 3.1.

Table 2-1 provides a listing of the "project" sources (i.e., the package boiler and the associated existing debottlenecked sources). Solvay has identified 22 existing sources which will be debottlenecked as a result of the installation of the new boiler. Of these sources, 16 are material handling sources with particulate emissions controlled by baghouses. Five are existing combustion sources with emissions controlled by electrostatic precipitators (ESPs). The combustion sources include calciners A through D, and two dryers; WDEQ considers the coal-fired calciners A and B as one source. Source #15 (Dryers #1 and #2) is a steam tube dryer only and does not have its own burner. Solvay has a small natural gas preheater installed on Dryers #1 and #2, but this preheater has not been used for several years. Solvay no longer wishes to use the Source #15 preheaters and wishes to eliminate them from the facility's air permit. As a result, Source #15 is not considered a combustion source here.

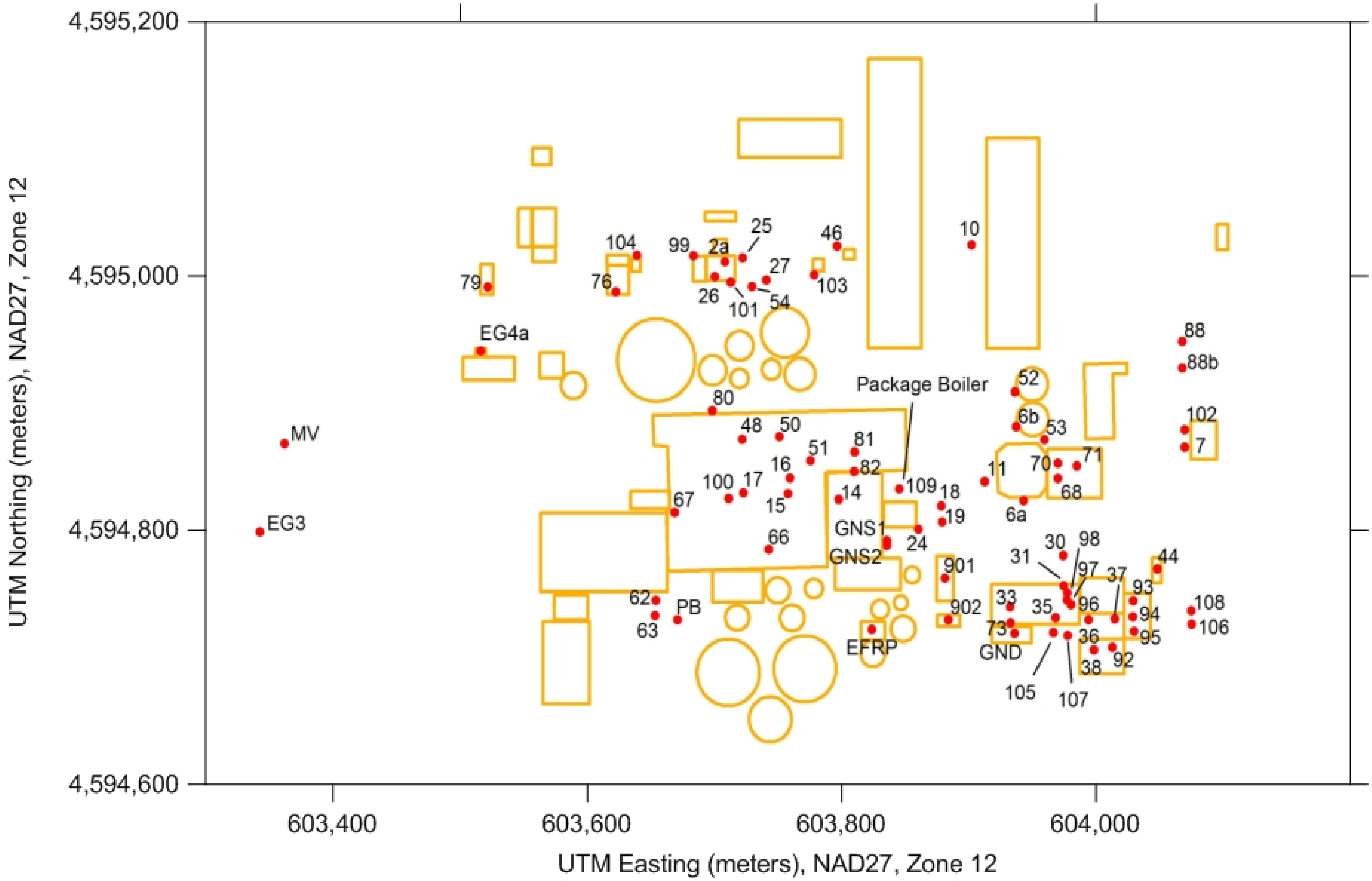
Table 2-1. List of Project Sources: Package Boiler and Debottlenecked Sources

WDEQ Source ID	Source Description	Type	Combustion Source?	Fuel(s)
109	Gas-fired Package Boiler	New Combustion	Yes	Gas
02A	Ore Crusher Building #1	Existing Baghouse	No	---
06A	Product Silos-Top	Existing Baghouse	No	---
06B	Product Silos- Bottom #1	Existing Baghouse	No	---
07	Product Loadout Station	Existing Baghouse	No	---
15	DR-1 & 2 Steam Tube Dryers	Existing Combustion, Scrubber	No*	None
16	Dryer Area	Existing Baghouse	No	---
17	"A" and "B" Calciners	Existing Combustion, ESP	Yes	Coal
46	Ore Transfer Station	Existing Baghouse	No	---
48	"C" Calciner	Existing Combustion, ESP	Yes	Gas
50	"C" Train Dryer Area	Existing Baghouse	No	---
51	Product Dryer #5	Existing Combustion, ESP	Yes	Gas
52	Product Silo- Top #2	Existing Baghouse	No	---
53	Product Silo- Bottom #2	Existing Baghouse	No	---
76	"D" Train Primary Ore Screening	Existing Baghouse	No	---
79	Ore Transfer Point	Existing Baghouse	No	---
80	"D" Ore Calciner	Existing Combustion, ESP	Yes	Gas
81	"D" Train Dryer Area	Existing Baghouse	No	---
82	DR-6 Product Dryer	Existing Combustion, ESP	Yes	Gas
99	Crusher Baghouse #2	Existing Baghouse	No	---
100	Calciner Coal Bunker	Existing Baghouse	No	---
103	East Ore Reclaim Baghouse	Existing Baghouse	No	---
104	West Ore Reclaim Baghouse	Existing Baghouse	No	---

* Source #15 fed by heat from boilers only, old preheaters on Source #15 are no longer used so there are no actual gaseous emissions.

The plant layout with the various buildings and all the facility emission points is shown on Figure 2-1, with the gas-fired package boiler location specified.

Figure 2-1. Solvay Facility Plant Layout and Emission Points



3.0 PSD APPLICABILITY ANALYSIS

According to draft WDEQ Operating Permit No. 3-1-126, the Solvay facility has the potential-to-emit (PTE) 487 tpy of PM and PM_{10}; 3,037 tpy of NO_x; 14,831 tpy of CO; 619 tpy of SO_2; 6,828 tpy of VOC; and 466 tpy of hazardous air pollutants (HAPs). In addition, the facility is a major source for $PM_{2.5}$ and GHG. Thus, the Solvay Green River facility is an existing major stationary source under the New Source Review (NSR), PSD permitting program because it has the potential to emit greater than 250 tpy of several criteria pollutants including PM, PM_{10}, $PM_{2.5}$, NO_X, CO, SO_2, VOC, and GHG. A project proposed at an existing major stationary source is subject to PSD review if the project is either a major modification to an existing major stationary source, or a major stationary source unto itself (meaning emissions from the project itself exceeds 250 tpy for a particular PSD pollutant).

For purposes of determining whether a project qualifies as a "major modification", thus triggering PSD review, Wyoming Air Quality Standards and Regulations (WAQSR), Chapter 6, Section 4(b)(i)(J)(I), indicates that a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases – a "Significant emissions increase" (as defined in WAQSR, Chapter 6, Section 4(a)), and a "Significant net emissions increase" (as defined in the definitions for "Net emissions increase" and "Significant" in Section 4(a)). The project is not a major modification subject to NSR review if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase. Significant emissions increase means that the emissions increase for any regulated NSR pollutant is greater than the NSR Significant Emission Rate (SER) threshold for that regulated pollutant (see WAQSR, Chapter 6, Section 4(a) definition of "significant").

3.1 Significant Emissions Increase from Project

Based on WAQSR, Chapter 6, Section 4(b)(i)(J)(II), the procedure for calculating whether a significant emissions increase will occur at a major stationary source depends on the units being modified. For new emissions units at the facility (i.e., the gas-fired package boiler), the increase in emissions is equal to the PTE of the unit and the baseline actual emissions (BAE) for the new source is zero. For existing emissions units (e.g., Solvay's debottlenecked sources), the increase in emissions is calculated as the difference between the projected actual emissions (PAE) and the BAE.

BAE are defined in WAQSR, Chapter 6, Section 4(a) for an existing emissions unit (other than an electric utility steam generating unit). BAE means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit PSD application is received by WDEQ, whichever is earlier. For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the

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emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

PAE are defined in WAQSR, Chapter 6, Section 4(a) for both new and existing units and means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project. In lieu of calculating PAE, the emissions for a unit may be calculated as the PTE for the unit.

Note that the PTE emissions calculation details and source release characteristics for the gas-fired package boiler are provided in Appendix C: and Appendix D: . The details regarding the PAE and BAE emission calculations for the existing debottlenecked sources are provided in Appendix E. To calculate BAE for the existing project sources, Solvay utilized five years (2006 to 2010) of facility-wide actual emissions information which is provided to WDEQ annually.

To determine the PAE from the existing project debottlenecked sources, Solvay assumed the following:

- There are no short-term (1-hour and 24-hour) increases in PTE for these sources,
- There is no need to physically modify existing equipment which can already accommodate anticipated production increases from debottlenecking,
- For baghouses which already operate 8,760 hours per year (#02A, #06A, #46, #99, #103, #104), there will be no annual emissions increases,
- For baghouses (and Source #15) which currently operate less than 8,760 hours per year, the projected actual emissions are estimated by scaling the annual operations/emissions up to 8,760 hours per year to conservatively estimate post-project debottlenecked operations, and
- For the combustion sources (#17, #48, #51, #80, #82), the highest year of actual emissions over five years (2006 to 2010) is increased by 14.1% to account for production increases as a result of debottlenecking. This increase is based on the ratio of the anticipated annual increase in soda ash production from the proposed project (360,000 tons/yr) to the average facility soda ash production over the five years as measured at the product load out station source, Source #7 (2,549,717 tons/yr). For SO_2 emissions from Source #17, the PAE using this scaling method would exceed the source's PTE; thus, the PTE is used as the PAE for #17.

As shown in Table 3-1, a summary of the emissions increases from the proposed project (new gas-fired boiler PTE emissions and debottlenecked sources) are compared to the PSD significant emission rates. The project emissions exceed the significant emission rates for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, and GHG, and will trigger PSD review if the net emissions increases for these pollutants exceed their significant emission rates (explained further in next section). SO_2, lead, fluorides, hydrogen sulfide (H_2S), and sulfuric acid mist (H_2SO_4) emissions from the project are not significant and these pollutants are not considered further since they do not trigger PSD.

The SO_2 emissions increase from the project is 0.8 tpy, well below the SO_2 significant emission rate of 40 tpy. SO_2 is emitted in small amounts from the gas-fired package boiler (PTE of 0.7 tpy) and the debottlenecked Source #17, A and B Calciners (PAE minus BAE of 0.1 tpy).

From Table 3-1, estimated increases in lead emissions from the project (0.005 tpy) are well below the corresponding significant emission rate of 0.6 tpy. Solvay has performed analytical testing on its feedstock ore and soda ash product and lead has not been detected in either (i.e., tests were below detection limits). Thus, there are no process emissions of lead at the facility. Lead is potentially emitted in trace quantities from the combustion sources as part of the project (#17, #48, #51, #80, and #82). A summary of the emissions inventory for the project (package boiler, debottlenecked sources, and contemporaneous sources) is provided in Appendix C: . The PTE emissions calculation details for the new gas-fired boiler for lead are provided in Appendix D: . The details regarding the PAE and BAE emission calculations for the existing debottlenecked sources are provided in Appendix E: .

From Table 3-1, estimated increases in fluoride emissions (as hydrogen fluoride, HF, from coal combustion) from the project (1.6 tpy) are below the corresponding significant emission rate of 3 tpy. There is no fluoride in Solvay's feedstock ore and soda ash product since the geographical formation around the facility is not favorable for fluorides. Thus, there are no process emissions of fluorides at the facility. Fluorine is a trace element in natural gas and when these fuels are burned, fluorine may be emitted as HF, but emissions from gas-combustion are not considered significant (e.g., there are no AP-42 emission factors for fluorine or HF). The primary source of HF emissions from the project sources is from coal combustion from Source #17, Calciners A and B, and the details regarding the PAE and BAE emission calculation for this existing debottlenecked source are provided in Appendix E: .

There are a few small existing emission sources of H_2S and H_2SO_4 emissions at the facility, but these sources are not affected by the proposed new boiler project. Thus, emissions of H_2S and H_2SO_4 will not increase as a result of the proposed boiler project and no further analysis is considered for these pollutants; these pollutants do not trigger PSD review.

Table 3-1. Emissions Increases from Project (Package Boiler and Debottlenecked Sources)

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
Baseline Actual Emissions (BAE) for Project	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	8.0	1,165,771	1,167,598
Package Boiler Emissions (PTE = PAE) >	8.3	8.3	8.3	12.2	41.2	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (PAE) >	224.7	224.7	224.7	503.3	5955.0	4.4	1873.7	0.028	9.6	1,529,044	1,531,350
Projected Actual Emissions (PAE) for Project	233.0	233.0	233.0	515.5	5996.1	5.0	1879.7	0.029	9.6	1,659,093	1,661,614
Project Emissions Increase	50.2	50.2	50.2	101.4	1564.8	0.8	438.6	0.005	1.6	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Is the Project Emissions Increase Significant?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

3.2 Net Emissions Increase from Project and Contemporaneous Sources

For all pollutants that will have a projected emissions increase that is greater than the SER (see Table 3-1), a further analysis is used to determine the creditable emissions increases and decreases that occurred during the contemporaneous period for purposes of determining the "net emissions increase" of that pollutant associated with the project. From Table 3-1, emissions of PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOCs, and GHG, exceed the SER. Emissions of SO_2, lead, fluorides, H_2S and H_2SO_4 are not significant and no further analysis is required; PSD does not apply to these pollutants. "Net emissions increase" is defined in WAQSR, Chapter 6, Section 4(a). In general, the net emission increase considers the significant emissions increases from the project (described in Section 3.1) and any other any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.

In general, an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the date five years before construction on the particular change commences and the date that the increase from the particular change occurs. In addition, an increase or decrease in actual emissions is creditable only if WDEQ has not relied on it in issuing a previous PSD permit for the source, which is in effect when the increase in actual emissions from the particular change occurs. Note that there have been no PSD permitting actions at the Solvay facility in the past five years (i.e., during the contemporaneous period) so this provision does not apply to the package boiler project.

Assuming that the proposed new boiler project were to begin construction around September 2013, the contemporaneous period would be defined as the period from September 2008 (five years before construction) to the date when the proposed project becomes operational. As provided in detail in Appendix F: , all permitting actions from September 2008 to present have been listed along with the facility sources affected by the permitting action. For those emissions which are creditable, the net emissions changes have been determined following WDEQ's definition of net emissions increase for contemporaneous sources. There have been 17 permitting actions at the facility since September 2008, not including this proposed package boiler permit action and the recent permit application submittal for the use of a temporary portable boiler. These actions are listed on Page 1 of Appendix F: .

Solvay has analyzed these permitting actions and contends that emissions associated with nine of these actions are not creditable (see Page 2, Appendix F:). As discussed with WDEQ at a February 23, 2012 meeting, emissions sources which were both introduced to and then removed from the facility during the contemporaneous period are not considered creditable. In addition, temporary projects and projects with no emissions changes or insignificant emissions changes are not considered creditable.

Creditable emissions increases at existing sources (i.e., sources in existence prior to the contemporaneous period) are provided in detail on Page 3 of Appendix F: . Creditable emissions increases at new sources (i.e., those sources permitted for the first time during the contemporaneous period) are provided in detail on Pages 5 and 6 of Appendix F: .

As part of the boiler project, Solvay wishes to remove the following sources from the facility: #64, #65, #72, #89, #90, and #91. Criteria pollutant emissions from Source #89 (Bisulfate Loadout Facility) are SO_2 only and since the project is not significant for SO_2, there is no need to consider the emissions from this source for netting/contemporaneous purposes.

The insignificant creditable PM emissions reductions (<0.1 tpy total) from Sources #64, #65, #72, #90, and #91 don't change any overall PSD applicability conclusions. To be creditable, the removal of these sources from the facility will be enforceable as a practical matter (i.e., removed from Solvay's air permit) when the proposed boiler project becomes operational. Details for these calculations are provided on Page 4 of Appendix F: .

Table 3-2 summarizes the net emissions changes from the project and associated contemporaneous emissions. As shown in Table 3-2 the inclusion of contemporaneous emission sources with the project emissions totals doesn't reduce emissions at the facility below significant emission rate levels. Thus, the following pollutants have net emissions increases as a result of the proposed project and PSD review is triggered for: PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, and GHG.

Table 3-2. Net Emissions Changes: Includes Both Project and Contemporaneous Sources

	PM ton/yr	**PM_{10} ton/yr**	**$PM_{2.5}$ ton/yr**	**NO_X ton/yr**	**CO ton/yr**	**SO_2 ton/yr**	**VOC ton/yr**	**Lead ton/yr**	**Fluorides ton/yr**	**GHG ton/yr**	**CO_2e ton/yr**
Package Boiler Emissions (Project)	8.3	8.3	8.3	12.2	41.2	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (Project)	41.9	41.9	41.9	89.1	1523.7	0.1	432.6	0.005	1.6	363,273	363,752
Project Subtotal >	50.2	50.2	50.2	101.4	1564.8	0.8	438.6	0.005	1.6	493,321	494,015
New Contemporaneous Sources	22.1	22.1	22.1	37.5	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Increases	7.2	7.2	7.2	1.1	0	N/A	0	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Decreases	-0.1	-0.1	-0.1	0	0	N/A	0	N/A	N/A	0	0
Contemporaneous Subtotal >	29.2	29.2	29.2	38.6	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Sum of Project and Contemporaneous Emissions	79.4	79.4	79.4	140.0	1594.1	N/A	447.8	N/A	N/A	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Trigger PSD?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

* The increase in GHG emissions from the project (i.e., package boiler and debottlenecked sources) is significant and there are no creditable contemporaneous decreases of GHG. Thus, project clearly triggers PSD for GHG (BACT for the package boiler applies regardless) and no further quantification is performed.

4.0 A
POLLUTION CONTROL REQUIREMENTS

The facility is presently permitted under Wyoming Department of Environmental Quality (WDEQ) Operating Permit No. 3-0-126-1 (effective February 28, 2006) and an updated operating permit, WDEQ Operating Permit No. 3-1-126 (currently draft) will replace permit No. 3-0-126-1. These permits incorporate applicable requirements for the existing sources at the facility. Thus, the New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPs), and Maximum Available Control Technology (MACT), and other permit-related applicability determinations below focus on the gas-fired package boiler only, not the existing sources.

4.1 New Source Performance Standards (NSPS)

WAQSR, Chapter 5, Section 2 (NSPS): The natural gas-fired package boiler will not provide steam for electric generation. Therefore, it will be subject to the NSPS for industrial–commercial–institutional steam generating units in 40 CFR 60, Subpart Db. Subpart Db applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity greater than 100 MMBtu/hr.

40 CFR 60, Subpart D applies to fossil-fuel-fired steam generating units that commenced construction or modification after August 17, 1971, and that have a heat input capacity greater than 250 MMBtu/hr. However, per 40 CFR 60.40b(j), any affected facility meeting the applicability requirements under 40 CFR 60.40b(a) (construction date after June 19, 1984 and boiler heat input greater than 100 MMBtu/hr) is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, 40 CFR 60.40). Thus, the Solvay package boiler is not subject to NSPS Subpart D, only Subpart Db.

The NOx standards in Subpart Db are specified by the type of fuel combusted. In 40 CFR 60.44b(a), the NOx emission limit is 0.20 lb/MMBtu for a high heat release boiler firing natural gas. Based on the gas-fired package boiler's rated heat capacity of 254 MMBtu/hr and a boiler volume of 3,567 ft^3 (inside furnace dimensions of 7.08′ wide x 13.71′ tall x 36.75′; see Appendix B:), the heat release rate for the new boiler is 71,208 Btu/hr-ft^3. Thus, the new boiler will have a maximum heat release rate of more than 70,000 Btu/hr-ft^3, a high heat release rate. Compliance with the NOx emission limit is to be determined on a 30-day rolling average basis and applies at all times, including startup, shutdown, and/or malfunction in accordance with 40 CFR 60.44b(h) and (i). Boilers with a heat input capacity of 250 MMBtu/hr or greater with an annual capacity factor for natural gas greater than 10% are required to install and operate a continuous emission monitoring system (CEMS) for NOx in accordance with 40 CFR 60.48b(b).

There are no applicable PM or SO_2 standards in Subpart Db for natural gas-fired boilers.

4.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)

WAQSR, Chapter 5, Section 3 (NESHAP): Section 112 of the 1990 Clean Air Act Amendments requires the U.S. EPA to develop standards to control major sources of HAPs to levels consistent with the lowest emitting facilities in similar source categories. These NESHAP require the application of the MACT. The U.S. EPA promulgated NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters under 40 CFR Part 63, Subpart DDDDD (September 13, 2004). However, on June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the standards. In response to the Court's vacatur and remand, on March 21, 2011, EPA established emission standards that will require industrial/commercial/ institutional boilers and process heaters located at major sources (i.e., "Major Source Boiler MACT" rules) to meet hazardous air pollutants standards reflecting the application of the MACT. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. The EPA subsequently issued a notice on May 18, 2011, to postpone the effective dates of the final rule until judicial review has been completed, or the agency finalizes its reconsideration of the standard, whichever is earlier. On January 9, 2012, the U.S. District Court for the District of Columbia Circuit vacated the EPA's May 18, 2011, notice that delayed the effective dates of the Boiler MACT rule. Due to the vacatur, the Boiler MACT rules have become effective. On December 23, 2011, EPA issued new proposed rules for public comment for 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters and EPA intends to finalize these proposed rules in 2012.

Solvay is an existing major source of HAPs (466 tpy); that is the facility emits, or has the potential to emit at least 10 tpy of individual HAPs or 25 tpy of combined HAPs. The new boiler in and of itself will not emit 10 tpy of any individual HAP or 25 tpy of combined of HAPs, but because the new boiler will be located at a major source of HAPs, the original March 21, 2011 Major Source Boiler MACT rules and eventually the finalized version of the proposed December 23, 2011 rules will apply to the facility. In these rules, if the unit (i.e., gas-fired package boiler at Solvay) combusts only natural gas, refinery gas, or equivalent fuel, the unit is subject to a work practice standard that requires periodic tune-ups, in lieu of emission limits.

WAQSR, Chapter 6, Section 5: This regulation is applicable because there is a MACT standard applicable to the new gas-fired boiler. This regulation implements the preconstruction review requirements of Section 112(i)(1) for sources subject to a relevant emission standard that has been promulgated under Chapter 5, Section 3 (i.e., NESHAP).

WAQSR, Chapter 6, Section 6 (Permit requirements for case-by-case maximum achievable control technology (MACT) determination): This regulation does not apply since there is a MACT standard applicable to the gas-fired package boiler. Thus, a case-by-case MACT determination is not necessary for the new boiler.

4.3 Other Applicable Air Pollution Control-Related Rules

Chapter 6, Section 2(a)(i): Solvay proposes to modify an existing facility, which may cause an increase in air contaminants. Thus, Solvay must obtain a construction permit.

Chapter 6, Section 2(b)(i): The application is to include plans, specifications, and the manner in which the sources are to be operated and controlled.

Baseline ambient monitoring may be required at the discretion of the Administrator. This proposed modification may result in a significant net emissions increase of criteria pollutants including PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC. Solvay previously monitored for NO_x and TSP, and is currently monitoring for PM_{10}. NO_x monitoring was discontinued in 1988 due to the low concentrations (average for 1987 was 5 $\mu g/m^3$). The on-site PM_{10} monitor has shown no exceedance of the Wyoming PM_{10} 24-hour or annual standards. Additional regional monitoring has been conducted for ozone throughout southwest Wyoming as part of the Wyoming Visibility Monitoring Network, for CO at the Yellowstone and Tata monitoring stations, for NO_2 at the Murphy Ridge and Moxa monitoring stations, and for $PM_{2.5}$ in Rock Springs. Solvay believes sufficient monitoring has been conducted to define a representative baseline for this application. The ambient baseline information representative of the facility location is provided in Section 7.5.4.

Chapter 6, Section 2(c)(ii): The application must demonstrate compliance with the Wyoming Ambient Air Quality Standards (WAAQS), as shown in Section 7.0 of this application.

Chapter 6, Section 2(c)(iii): The application must demonstrate compliance with PSD increments, as shown in Section 7.0 of this application.

Chapter 6, Section 2(c)(v): The sources must utilize the Best Available Control Technology (BACT). A BACT analysis for criteria pollutants is found in Section 5.0 of this application.

Chapter 6, Section 2(c)(vi): The facility must have provisions for measuring the emissions of significant air contaminants as determined by the Administrator. These are already in place for the existing sources at the facility, as described in the current Permit OP 3-0-126-2 (2006) and the draft Permit OP 3-1-126. The new gas boiler will not trigger the 40 CFR Part 64 Compliance Assurance Monitoring (CAM) requirements as described in WAQSR, Chapter 7, Section 3. CAM applies to applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria (per WAQSR, Chapter 7, Section 3(b)):

- the unit is subject to an emission limit or standard for an applicable regulated air pollutant,
- the unit uses a control device to achieve compliance with the applicable emission limit or standard, and
- the unit has potential pre-control device emissions of the applicable regulated air pollutant of 100 tpy.

The new package boiler is subject to NSPS, Subpart Db standards and monitoring which require CEMS for NOx. Therefore, CAM is not considered for the new package boiler since CEMS satisfies WAQSR, Chapter 7, Section 3(c)(iv)(B) requirements for CAM. In addition, the new boiler will utilize an ultra-low NO_X burner (ULNB) in conjunction with flue gas recirculation (FGR). ULNB is not considered an add-on "control device" per WAQSR, Chapter 7, Section 3(a) definition of "control device". FGR is a design feature of modern gas-fired boilers which are often used in conjunction with low NOx boilers. The FGR is technically a control device by itself per WAQSR definitions, but FGR use is integrally tied to the proper operation of the ULNB in the new package boiler. The FGR does not operate independently of the ULNB and Solvay would need to stop operations of the boiler if there were problems with the FGR to avoid damaging/over-heating the ULNB. Thus, Solvay does not consider the ULNB-FGR combination a "control device". The new package boiler fitted with ULNB-FGR has potential emissions of NOx (9 ppm, 12.2 tpy) and CO (50 ppm, 41.2 tpy) which are less than 100 tpy so CAM does not apply to the boiler.

Chapter 6, Section 3 (Major Source Operating Permits): Solvay is subject to these requirements and will submit a separate application for that purpose within 12 months after the boiler project commences operation, as required.

Chapter 6, Section 4(b)(i)(J)(I)): For purposes of determining whether a project qualifies as a major modification, thus triggering PSD review, this regulation requires a determination of two types of emissions increases – a "Significant emissions increase" (as defined in WAQSR, Chapter 6, Section 4(a)), and a "Significant net emissions increase" (as defined in the definitions for "Net emissions increase" and "Significant" in Section 4(a). As discussed in more detail in Section 3.0 of this report, the following pollutants have net emissions increases as a result of the proposed boiler project and PSD review following Chapter 6, Section 4 procedures is triggered for: PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, and GHG.

5.0 PROPOSED CONTROLS – BACT FOR CRITERIA POLLUTANTS

Pursuant to WAQSR, Chapter 6, Section 2(c)(v), Solvay is to provide a Best Available Control Technology (BACT) analysis for its proposed boiler project for pollutants which have a net emissions increase. As discussed in Section 3.0 of this report, the boiler project results in a net emissions increase and triggers PSD, including BACT review, for PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, and GHG. This section presents the BACT analysis for PM, PM_{10}, $PM_{2.5}$, NOx, CO, and VOC. The BACT analysis for GHG is discussed separately in Section 6.0 of this report.

As discussed with WDEQ at a February 23, 2012 meeting, a BACT analysis is only applicable to the gas-fired package boiler. BACT is not applicable to the existing debottlenecked sources which will not be physically modified as part of the project and BACT is not applicable to the contemporaneous sources. As noted in EPA's PSD and Title V Permitting Guidance from Greenhouse Gases[1], for existing sources triggering PSD review, EPA rules (40 CFR 52.21(j)(3)) are explicit that BACT applies to those emission units at which a net emissions increase would occur at the source as a result of a physical change or change in the method of operation. EPA has interpreted these provisions to mean that BACT applies in the context of a modification to only an emissions unit that has been modified or added to an existing facility. Since Solvay's existing debottlenecked sources will not be modified, they are not subject to BACT[2].

BACT is defined in Wyoming Air Regulations, Chapter 6, Section 4(a) as:

> *…an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under these Standards and Regulations or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible, he may instead prescribe a design, equipment, work practice or operational*

[1] EPA's PSD and Title V Permitting Guidance for Greenhouse Gases, Page 23: http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[2] In the preamble for the 1980 rule that established the current version of 40 CFR 52.21(j)(3), EPA explained that "BACT applies only to the units actually modified." 45 FR 52676, 52681 (Aug. 7, 1980). Later in this preamble, EPA elaborated as follows with a specific example: The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source. *Id.* at 52722. *See also* Letter from Robert Miller, EPA Region 5 to Lloyd Eagan, Wisconsin DNR (Feb. 8, 2000) (PSD applicability for debottlenecked source).

standard or combination thereof to satisfy the requirement of Best Available Control Technology. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results. Application of BACT shall not result in emissions in excess of those allowed under Chapter 5, Section 2 or Section 3 of these regulations and any other new source performance standard or national emission standards for hazardous air pollutants promulgated by the EPA but not yet adopted by the State of Wyoming.

The Environmental Protection Agency (EPA) provides guidance on the performance of BACT review in its October 1990 *Draft – New Source Review Workshop Manual*, commonly known as the "Puzzle Book," and this guidance is used herein for the typical top-down approach for determining BACT. In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps, for each pollutant to which BACT applies:

Step 1: Identify all available control technologies.

Step 2: Evaluate the technical feasibility of options from Step 1 and eliminate options that are technically infeasible based on physical engineering principles.

Step 3: Rank the remaining control technologies from Step 2 by control effectiveness, in terms of emission reduction potential.

Step 4: Evaluate the most effective controls from Step 3, considering economic, environmental, and energy impacts of each control option. If the top option is not selected, evaluate the next most effective control option.

Step 5: Select BACT (the most effective option from Step 4 not rejected).

Available control technologies for the new gas-fired boiler have been gathered from the *EPA Air Pollution Control Cost Manual*,[3] the EPA RACT/BACT/LAER[4] Clearinghouse (RBLC), the California Air Resources Board Statewide Best Available Control Technology Clearinghouse (CA-BACT) database, a review of the literature of BACT analyses for similar sources,[5] and a review of pollutant control technologies from EPA's Clean Air Technology Center (CATC) webpage.[6] Table 5-1 provides a summary of the proposed BACT limits and associated control technologies for Solvay's gas-fired boiler. The following sections utilize these data sources and provide the BACT analyses for NOx, PM, PM_{10}, $PM_{2.5}$, CO, and VOC.

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[3] EPA, document no. EPA/452/B-02-001: *EPA Air Pollution Control Cost Manual*, Sixth Edition, January 2002.

[4] RACT = Reasonably Available Control Technology; LAER = Lowest Achievable Emission Rate

[5] We Energies, Rothschild, Wisconsin: http://www.nobiomassburning.org/OLD/BAP/Ash_files/We%20Energies%20air_permit_application.pdf

[6] EPA CATC webpage: http://www.epa.gov/ttn/catc/products.html

Table 5-1. Summary of Solvay's Proposed BACT Limits for Gas-Fired Package Boiler

Pollutant	Proposed Emission Limit (lb/MMBtu)	Proposed Control Technologies
NOx	0.011	Combination of ultra-low NOx burners, flue gas recirculation, and good combustion practices.
PM/PM_{10}	0.0075	Use of natural gas as fuel combined with good combustion practices.
$PM_{2.5}$	0.0075	Use of natural gas as fuel combined with good combustion practices.
CO	0.037	Good combustion practices.
VOC	0.0054	Good combustion practices.

5.1 BACT Review – NO_X Emissions

The BACT review process described in Section 5.0 is applied to potential NO_X emission controls for Solvay's natural-gas fired package boiler in this subsection.

As described in EPA's AP-42, Section 1.4 (Natural Gas Combustion), nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NOx formation in natural gas combustion is thermal NOx. The thermal NOx mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NOx formed through the thermal NOx mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NOx is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NOx emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NOx formation, called prompt NOx, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx reactions occur within the flame and are usually negligible when compared to the amount of NOx formed through the thermal NOx mechanism. However, prompt NOx levels may become significant with ultra-low-NOx burners.

The third mechanism of NOx formation, called fuel NOx, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NOx formation through the fuel NOx mechanism is insignificant.

5.1.1 Identify all Available NO_X Combustion Control Technologies

NOx controls for natural gas-fired boilers are addressed in AP-42 Section 1.4. There are two major technology categories for controlling NOx emissions from boilers: combustion controls and post-combustion controls. Currently, the two most prevalent combustion control techniques used to reduce NOx emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NOx burners (LNB) which control residence time, oxygen, and combustion temperature to limit NOx formation. Some additional combustion control techniques used to reduce NOx emissions include staged combustion and gas reburning.

Post-combustion NOx control systems are designed to reduce emissions after NOx has been created. Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NOx emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). SNCR and SCR NO_X control technologies are discussed in greater detail in the *EPA Air Pollution Control Cost Manual*,[7] Section 4.2. Based on a review of these documents, the literature for comparable boilers, and the RBLC and CA-BACT databases, the potential control technologies for natural gas-fired package boiler NOx emissions are:

Combustion Controls

- Low NOx burners (LNB) and Ultra-Low NOx Burners(ULNB)
- Flue Gas Recirculation (FGR)
- Overfire air (OFA)
- Good Combustion Practices (GCP); i.e., Combustion Optimization
- Low Excess Air (LEA)
- Oxygen-Enhanced Combustion (OEC)
- Fuel Reburn (FR)
- Burners Out of Service (BOOS)

Add-on Controls

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Non-selective Catalytic Reduction (SCONOx™)

Table 5-2 summarizes the NOx BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA's RACT/BACT/LAER Clearinghouse. The technologies identified include low NOx burners (LNB), ultra-low NOx burners (UNLB), Flue Gas Recirculation (FGR), Good Combustion Practices (GCP), Selective Catalytic Reduction (SCR), and the use of clean burning fuels (i.e., natural gas) or combinations of these controls. Emission limits range from 0.010 to 0.0281 lb/MMBtu for natural gas combustion. Many of the emission limits in these tables were expressed as pounds per hour in the original database searches, but were converted to lb/MMBtu to make the emission limits comparable.

For the RBLC searches, the EPA database was queried for natural gas combustion (primarily RBLC codes 11.310 for > 250 MMBtu/hr and 12.310 for 100 – 250 MMBtu/hr) for the lowest NOx emission rates and

[7] *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA-452-02-001, January, 2002, Section 4.2

the subsequent results were culled so that only boilers with ratings greater than 100 MMBtu/hr (roughly ½ the size of the Solvay boiler) and less than 500 MMBtu/hr (roughly twice the size of the Solvay boiler) were included. Searches which provided non-boiler emission sources such as duct burners at power plants were removed so that only boiler-type sources were included. In addition, the RBLC lowest limit searches were supplemented with recent BACT determinations research which was performed for similar package boilers. Only limits used for BACT determinations, and not "case-by-case" or "other" determinations are considered for the listings in Table 5-2.

There is one CA-BACT listing for boilers between 100 MMBtu/hr and 500 MMBtu/hr (Darling International Inc., 110 MMBtu/hr gas-fired boiler) with a NOx limit of 9 ppmvd at 3% oxygen based on the use of LNB-FGR control technology. Using EPA Method 19 to convert units from ppm to lb/MMBtu, this emission rate is roughly equal to 0.011 lb/MMBtu, comparable to the lowest NOx emission rates from the RBLC.

Table 5-2. NO_X Control Determinations for Natural-Gas Boilers from RBLC and CA-BACT

RBLC ID	RBLC Process Type	Facility	Permit Date	Process	Throughput (MMBtu/hr)	Controls	BACT Limit (lb/MMBtu)
LA-0229	12.310	Shintech Plaquemine Plant 2	07/10/08	Utility Boilers	250.0	LNB, SCR	0.010
TX-0499	12.310	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175.0		0.010
TX-0511	11.310	BASF Fina Petrochemicals	02/03/06	2 Boilers	425.4		0.010
OR-0046	12.310	Calpine Turner Energy Center	01/06/05	Auxiliary Boiler	139.0	SCR	0.011
AZ-0046	11.310	Arizona Clean Fuels Yuma LLC	04/14/05	2 Boilers	419.0	LNB, FGR	0.013
MI-0389	12.310	Consumers Energy	12/29/09	Boiler	220.0	LNB	0.018
IA-0088	11.310	Archer Daniels Midland	06/29/07	2 Boilers	292.5	ULNB, FGR, GCP	0.020
ID-0017	12.310	Southeast Idaho Advanced Energy Center	02/10/09	Package Boiler	250.0	LNB, FGR	0.020
WA-0301	11.310	British Petroleum	04/20/05	Boiler	363.0	ULNB, FGR	0.028
ND-0025	11.310	Tharaldson Ethanol Plant 1, LLC	12/20/07	Boiler	480.0	ULNB, FGR	0.033
AL-0230	13.310	Thyssenkrupp Steel and Stainless	08/17/07	3 Boilers	65.0	ULNB, FGR	0.035
IN-0085	12.310	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125.0	LNB	0.036
AL-0160	11.310	Mobile Energy LLC	06/07/00	Boiler	378.0	LNB, FGR	0.036
AR-0026	12.310	Pine Bluff Energy Center	05/05/99	Boiler	362.0	LNB, FGR, GCP	0.037
CO-0052	12.310	Rocky Mountain Energy Center	08/11/02	Auxiliary Boiler	129.0	LNB	0.038
CO-0041	11.310	American Soda LLP, Pineance Facility	05/06/99	2 Boilers	258.7	LNB	0.038
LA-0177	11.310	Amerada Hess Corp.	09/08/05	Boiler	363.0	LNB, FGR	0.040
MN-0062	12.310	Heartland Corn Products	12/22/05	Boiler	198.0		0.040
AR-0057	12.310	Tenaska Arkansas Partners, LP	10/09/01	Boiler, (2)	122.0	FGR	0.040
TX-0411	12.310	Calpine Amelia Energy Center	03/26/02	Auxiliary Boiler	155.0		0.040
SC-0061	11.310	Columbia Energy LLC	04/09/01	2 Boilers	350.0	LNB, FGR, GCP	0.040
SC-0071	11.310	Columbia Energy LLC	04/09/01	2 Boilers	350.0	LNB, FGR, GCP	0.040
LA-0177	11.310	Amerada Hess Corp.	09/08/05	Boiler	363.0	LNB, FGR	0.040
IA-0050	12.310	Cargill - Eddyville	04/22/99	Boiler 7	182.0	LNB, FGR	0.050
AL-0199	11.310	Weyerhaeuser Company	11/15/02	Boiler	300.0	LNB	0.050
NE-0013	11.310	Cargill, Inc.	09/30/99	Boiler	276.7	LNB, FGR	0.050
TX-0371	11.310	Corpus Christi Cogen LP	02/04/00	3 Auxiliary Boilers	315.0		0.052
AL-0128	12.310	Alabama Power - Theodore Cogeneration	03/16/99	Boiler	220.0	LNB, FGR	0.053
TX-0293	11.310	Gregory Power Partners LP	06/16/99	2 Auxiliary Boilers	405.0	Natural Gas	0.054
FL-0251	12.310	Okeelanta Corporation Sugar Mill	10/29/01	Boiler	211.0	LNB, FGR, GCP	0.060
LA-0124	11.310	PPG Industries	11/23/99	2 Boilers	356.0	LNB, FGR	0.060
OH-0269	11.310	Biomass Energy	01/05/04	Auxiliary Boiler	247.0		0.060
OH-0307	11.310	Biomass Energy	04/04/06	Auxiliary Boiler	247.0		0.060
TN-0153	12.310	Williams Refining and Marketing, LLC	04/03/02	Boiler, No. 10	180.0		0.060
TX-0419	11.310	Calpine Construction Finance Co. LP	03/22/00	3 Auxiliary Boilers	380.0	GCP	0.060
TX-0414	12.310	Fina Oil & Chemical Company	04/22/99	Boiler	227.0	GCP	0.060
LA-0183	12.310	Louisiana Pigment Co. Titanium Dioxide Facility	11/14/03	Utility Boilers	135.0	LNB, GCP	0.074
TX-0416	11.310	Shell Oil Company	11/24/99	Boiler	357.0	GCP	0.085
MS-0069	12.310	Dupont Delisle Facility	06/08/04	Boiler	231.0	LNB, FGR	0.090
WV-0023	12.310	Maidsville Longview Power, LLC	03/02/04	Auxiliary Boiler	225.0	LNB, GCP	0.098
WV-0015	12.310	E.I. DuPont De Nemours and Company	01/02/02	Boiler	181.0	LNB, FGR, GCP	0.100
WI-0228	12.310	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230.0	LNB, GCP	0.100
VA-0270	12.310	Virginia Commonwealth University East Plant	03/31/03	Boiler	150.0	LNB, FGR, GCP	0.100
VA-0278	12.310	Virginia Commonwealth University	03/31/03	3 Boilers	150.8	LNB, FGR, GCP	0.103
IA-0067	11.310	Midamerican Energy Company	06/17/03	Auxiliary Boiler	429.4	LNB	0.140
OH-0310	12.310	American Municipal Power	10/08/09	Auxiliary Boiler	150.0		0.140
NC-0101	12.310	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.2	LNB, GCP, Nat. Gas.	0.137
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	118.0		0.280
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	152.0		0.280
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	134.0		0.281
OR-0040	13.310	Klamath Generation	03/12/03	Auxiliary Boiler			30 ppmvd @ 3% O_2

Combustion Controls

Various combustion controls exist for NOx reduction from combustion units. Many of these techniques are designed to result in a longer, cooler flame which forms less NOx. These NOx control techniques include the following:

Low NOx Burners (LNB) and Ultra-low NOx Burners (ULNB): According to AP-42, Section 1.4, the two most common types of LNB being applied to natural gas-fired boilers are staged air burners and staged fuel burners. LNB are designed to control the mixing of air and fuel to reduce the peak temperatures of combustion in natural gas and fuel oil-fired boilers. LNB reduce NOx emissions by staging the combustion process and providing a stable flame that has several different zones. Staging slows down the combustion process, resulting in cooler flame temperatures which suppress thermal NOx formation.

LNB are designed to control fuel and air mixing at the burner in order to create larger flame patterns. This reduces the peak flame temperature and results in lower thermal NOx formation. The modified flame structure also reduces the amount of oxygen available in the hottest part of the flame, improving burner efficiency. Second generation low NOx burners are called Ultra Low NOx Burners (ULNB). LNB and ULNB are an available and highly effective NOx control technology for natural gas-fired boilers.

Flue Gas Recirculation (FGR): FGR is a combustion process often used in conjunction with LNB to reduce peak flame temperatures, thus suppressing thermal NOx formation, and to create an oxygen depleted zone in the boiler by reducing the concentration of oxygen in portions of the furnace. FGR reduces the oxygen content of the air at the base of the furnace by diluting the primary air blown into the furnace with recirculated flue gas from the back pass of the boiler. This technique is used to create an oxygen depleted reducing zone where unburned hydrocarbon species act to reduce the NOx that was formed near the burner. This oxygen depleted zone also reduces the peak flame temperatures which minimizes NOx formation.

The amount of recirculated flue gas is a key operating parameter influencing NOx emission rates for these systems. An FGR system is normally used in combination with specially designed LNB capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When LNB and FGR are used in combination, these techniques are capable of reducing NOx emissions by roughly 60 to 90 percent.

Overfire Air (OFA): OFA is a combustion staging processes typically used in conjunction with LNB. When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. A portion of the combustion air is redirected from the LNB to a higher elevation in the furnace to reduce peak flame temperatures by reducing the concentration of oxygen in portions of the furnace. This technique is used to create an oxygen depleted zone where unburned hydrocarbons act to reduce the NOx that was formed near the burner. The overfire air creates an oxidation zone to complete combustion and NOx formation is minimized by completing combustion in an air-lean environment.

Good Combustion Practices (GCP): Combustion controls are also referred to as good combustion practices which include good burner design, optimizing the air and fuel flow rates to the boiler, and good maintenance practices. Proper operation and maintenance of the combustion system helps to minimize the formation and emission of NOx by ensuring that the system operates as designed. Good combustion practices seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency and include process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions.

Low Excess Air (LEA): LEA is a good combustion practice for minimizing NOx emissions. LEA is implemented by limiting the amount of air used in fuel combustion, and by preventing air leaks into the furnace/boiler combustion zone. LEA reduces NOx emissions by limiting the amount of oxygen in the combustion zone which can react with nitrogen to form NOx. The LEA control efficiency is typically in the 1% - 15% range.

Oxygen-Enhanced Combustion (OEC): OEC is a combustion control technology aimed at reducing the formation of thermal NOx and is a method which uses oxygen to achieve additional NOx reduction from LNB on pulverized coal-fired boilers. OEC has not been utilized on natural gas-fired boilers and because there is no operational experience/significant technological questions with OEC on these natural gas-fired boilers, OEC is not a technically feasible control option[8].

Fuel Reburn (FR): FR is similar to the use of OFA in the use of combustion staging. Reburning redistributes a portion of both fuel and air into the upper regions of the boiler furnace to create a second flame zone, generating conditions that destroy NOx in the primary combustion zone. Based on a review of similar boiler sources, this reburning process is not applicable to natural gas-fired boilers and is not a technically feasible control option.

Burners Out of Service (BOOS): BOOS is a relatively simple technique used mostly in retrofit situations (suspension-fired coal and oil/gas-fired boilers) wherein multiple burners exist and fuel flow is blocked to an upper level of burners, allowing only air to pass through these. This control technique is only applicable to boilers with multiple burners.

[8] We Energies, Rothschild, Wisconsin:
http://www.nobiomassburning.org/OLD/BAP/Ash_files/We%20Energies%20air_permit_application.pdf

Add-on Controls

Add-on controls are post-combustion technologies that operate to reduce the level of NOx in the flue gas and include the following:

Selective Catalytic Reduction (SCR): The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and the reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen. Temperature, the amount of reducing agent, injection grid design, and catalyst activity are the main factors that determine the actual removal efficiency. The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of each catalyst used and the flue gas composition and typically varies from 480°F to 800°F. [9]

SCR is one of the most effective NOx abatement techniques and is capable of NOx reduction efficiencies of 70 to 90% and can achieve even higher NOx reductions. However, this technology has a high initial cost. In addition, catalysts have a finite life in flue gas and some ammonia "slips through" without being reacted. [10] Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent.

Selective Non-Catalytic Reduction (SNCR): In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into the boiler where the flue gas temperature is approximately 1600°F to 2100°F. At these temperatures, the reagent, either urea or ammonia, reacts with NOx, forming elemental nitrogen and water vapor without the need for a catalyst. This technique requires excellent ammonia/flue gas mixing, which necessitates large furnace volumes and residence times within a precise and stable temperature window in the furnace at which to inject the ammonia or urea.

The overall NOx reduction reactions are similar to those for the SCR systems. SNCR is better suited for applications with high levels of particulates in the waste stream gas than SCR. The limiting factor for a SNCR system is the ability to contact the NOx with the reagent as the concentration decreases without resulting in excessive ammonia slip and without excessive ammonia decomposition before the NOx emissions can be reduced.

SNCR is capable of NOx reduction efficiencies of 30 to 50% and can achieve even higher NOx reductions when applies in conjunction with combustion controls such as LNB (65% to 75% reductions).[11]

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[9] EPA, document no. EPA-452/F-03-032: *Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction*, http://www.epa.gov/ttn/catc/dir1/fscr.pdf

[10] EPA Technical Bulletin, Nitrogen Oxides (NOx), Why and How They are Controlled, EPA-456/F-99-006R, November 1999. http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf

[11] EPA, document no. EPA-452/F-03-031: *Air Pollution Control Technology Fact Sheet – Selective Non-Catalytic Reduction*, http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

SNCR has been widely used in fluidized bed boilers where the high alkaline ash loading of these boilers makes high dust loading SCR systems technically infeasible. SNCR has also been widely used in modern stoker boilers which are more ideal for application of this technology due to their large furnace volumes and relatively constant temperatures which provide a stable window for ammonia/flue gas mixing. However, SNCR is not appropriate for use in package natural gas-fired boilers, since the short residence time and small furnace volume does not allow for adequate reaction time to reduce NOx emissions. Package boilers may also operate with wide ranges in boiler steam load which causes the flue gas temperature to shift outside the optimum temperature window (unlike a more constant utility boiler type operation where SNCR might be feasible). There are no BACT determinations from the RBLC or CA-BACT which list SNCR for gas-fired boilers. Therefore, SNCR is not considered a technically feasible control option for package boilers.

Non-selective Catalytic Reduction (SCONOx™): SCONOx™ is a control technology that has been applied in combustion turbine applications and is employed at a few select facilities. The SCONOx system is based on a proprietary catalytic oxidation and absorption technology. In operation, NO and CO are first oxidized to NO_2 and CO_2. Next, NO_2 is adsorbed onto an adsorption media. When the media is saturated, NO_2 is desorbed and treated by the proprietary catalyst. Because the operation of SCONOx to oxidize CO to CO_2 is identical to the simple use of an oxidation catalyst, there is effectively no difference between SCONOx and an oxidation catalyst in terms of CO and VOC control. Therefore, SCONOx and an oxidation catalyst are effectively the same technology for controlling CO and VOC emissions.

To date, SCONOx has only been installed on small scale natural gas-fired combustion turbines. Therefore, this technology is not technically feasible for package boilers. There are no BACT determinations from the RBLC or CA-BACT which list SCONOx for gas-fired boilers. Thus, SCONOx is not a technically feasible control option for package boilers.

Other Controls: A search of the RBLC and CA-BACT databases for other possible NO_x control technologies applied to natural gas-fired boilers did not yield any controls technologies in addition to those listed above.

5.1.2 Eliminate Technologically Infeasible Technologies

Table 5-3 summarizes the feasibility of potential NOx controls for natural gas-fired package boilers. The combustion control technologies which are considered feasible for natural-gas fired package boilers are LNB/ULNB in conjunction with combustion controls of FGR, OFA, GCP, and LEA. Solvay has identified the only potentially applicable add-on control to gas-fired package boilers as SCR.

Table 5-3. Candidate NO_X Controls

Control Technology	Technically Feasible?	Notes
Low NOx Burners (LNB) and Ultra Low NOx Burners (ULNB)	Feasible	Widely used to control NOx.
Flue Gas Recirculation (FGR)	Feasible	Design feature of modern gas-fired boilers; often used in conjunction with low NOx burners.
Overfire Air (OFA)	Feasible	Design feature of modern gas-fired boilers.
Good Combustion Practices (GCP)	Feasible	Design feature of modern gas-fired boilers.
Low Excess Air (LEA)	Feasible	Combustion control method to reduce the amount of oxygen in the combustion zone of a boiler.
Oxygen-Enhanced Combustion (OEC)	Infeasible	Never applied to natural gas-fired boilers.
Fuel Reburn (FR)	Infeasible	Never applied to natural gas-fired boilers.
Burners Out of Service (BOOS)	Infeasible	BOOS is applicable to boilers with multiple burners; package boilers only have one burner.
Selective Catalytic Reduction (SCR)	Feasible	Applied to field-erected boilers and assumed theoretically transferrable technology to package boilers.
Selective Non-Catalytic Reduction (SNCR)	Infeasible	Not applicable to package boilers where short residence time and small furnace volume does not allow for adequate mixing and reaction time to reduce NOx.
Non-selective Catalytic Reduction (SCONOx™)	Infeasible	Applied to gas-fired turbines only, not boilers.

5.1.3 Rank the Remaining Technologies by Control Effectiveness

Solvay has grouped the remaining feasible controls technologies into two categories. For reference, the existing Solvay boiler has a LNB and FGR. Solvay has obtained a manufacturer's guarantee (Coen) for its existing package boiler configuration prior to installation of ULNB-FGR as 0.038 lb/MMBtu for NOx which represents a baseline emissions level of control. From this existing baseline boiler configuration, Solvay considers the following two theoretical control combinations for a boiler retrofit starting with the highest ranked NOx control combination:

- ULNB, FGR, and GCP and SCR to limit NOx emissions to 0.010 lb/MMBtu, and
- ULNB, FGR (upgrade existing fan), and GCP to limit NOx emissions to 0.011 lb/MMBtu (9 ppm).

The highest ranked remaining NOx control combination (i.e., lowest NOx expected emissions) is for a package boiler with ULNB, FGR, GCP and SCR installed. This combination is the based on the lowest NOx emission rate from the RBLC summary table in Table 5-2 for the Shintech Plaquemine Plant 2 in Louisiana which utilizes this control combination for a NOx emission limit of 0.010 lb/MMBtu.

The second highest ranked NOx control combination is for a Solvay package boiler outfitted with ULNB, FGR (upgraded fan), and GCP, but not SCR. This combination results in NOx emissions around 9 ppm at 3% oxygen (0.011 lb/MMBtu) per a manufacturer's proposal provided to Solvay by Coen for the retrofit of the Solvay package boiler (see Appendix B:).

5.1.4 Evaluate the Most Effective Control Based on a Case-by-Case Consideration of Energy, Environmental, and Economic Impact; Then Select the NO_X BACT

Highest Ranked Combination of ULNB, FGR, GCP and SCR: As noted above, the use of SCR in combination with ULNB, FGR, and GCP is expected to limit NOx emissions to around 0.010 lb/MMBtu. The cost calculations for a theoretical SCR system (existing baseline configuration compared to SCR installation) are provided in detail in Appendix G: , Pages 1 through 4. Compared to the existing boiler configuration emissions of 42.3 tpy NO_x (0.038 lb/MMBtu), a UNLB, FGR, GCP, and SCR system (0.010 lb/MMBtu) would be expected to reduce NO_x emissions to 11.1 tpy, a reduction of 31.2 tpy.

SCR systems have very high costs which include the total capital investment ($3,287,415), and the following annual costs: maintenance ($49,311/yr), reagent ($8,433/yr), electrical cost ($35, 437/yr), and catalyst replacement ($23,225/yr) for a total annual cost of $337,372. The removal of 31.2 tpy at this cost is $10,830/ton NOx removed. Also, note that the incremental cost to reduce emissions from the second highest ranked control combination of ULNB, FGR, GCP (0.011 lb/MMBtu) to one also including SCR (see Appendix G: , Pages 5 through 8). These costs are very high, indicating that the use of the SCR on Solvay's gas-fired package boiler is not economically feasible.

In addition to high costs, the use of SCR would also have adverse environmental impacts. Ammonia slip emissions from the operation of the SCR system would result in direct emissions of ammonia and ammonium nitrate and ammonia will react with sulfate in the atmosphere to form ammonium sulfate; both contribute to the formation of $PM_{2.5}$. Energy impacts from the use of SCR would include the increased electric energy required for the induced draft fans to overcome the increase in pressure drop across the SCR system.

Second Highest Ranked Combination of ULNB, FGR (upgrade fan), GCP (9 ppm NOx): The use of ULNB, FGR (upgrade existing fan), and GCP is expected to limit NOx emissions to around 9 ppm, or 0.011 lb/MMBtu NOx. The cost calculations for this control technology combination are provided in detail in Appendix G: , Pages 9 through 11. Compared to the existing boiler configuration emissions of 42.3 tpy NOx (0.038 lb/MMBtu), a UNLB, FGR, GCP system (9 ppm; 0.011 lb/MMBtu) would be expected to reduce NOx emissions to 12.2 tpy, a reduction of 30.0 tpy.

The incremental costs to upgrade Solvay's existing burner to a ULNB and to upgrade the existing FGR fan are estimated in Appendix G: , Pages 10 and 11. The cost calculations indicate a total capital investment of $1,150,854 with increased annual maintenance ($20,000/yr) and increased annual electricity costs to operate a larger, upgraded FGR fan ($74,469/yr). The removal of 30.0 tpy for this control combination at is estimated at $5,345/ton NOx removed. These costs are still high and could be argued too high to qualify as BACT. Regardless, Solvay is committing to upgrade the new package boiler with ULNB-FGR to control NOx to 9 ppm (0.011 lb/MMBtu) which is consistent with the most recent (lowest emitting) BACT determinations for natural gas-fired boilers.

5.2 BACT Review – PM and PM_{10} Emissions

The BACT review process described in Section 5.0 is applied to potential PM and PM_{10} emission controls for Solvay's natural-gas fired package boiler in this subsection.

Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. PM which exists as a solid or liquid at temperatures of approximately 250°F are measured using U.S. EPA's Reference Method 5, and are referred to as "front half" (i.e., filterable) emissions. Because natural gas is a gaseous fuel, filterable PM emissions are typically low.

PM which exists as a solid or liquid at a lower temperature (filtration temperature not exceeding 85°F) are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "condensable" PM. Condensable particulates are in a vapor state when emitted, and change to a liquid or solid state when cooled. Condensable PM may include acid gases, VOC and other materials, but does not include condensed water vapor.

The control efficiency of a PM control method depends upon the size distribution of the particulates in the waste gas stream.   Generally, the smallest particulates are the most difficult to remove. Particulate matter emission controls generally only capture particulate matter when it is in a filterable state (solid or liquid not a vapor). So, the ability of any specific type of particulate control device is dependent upon the process conditions at the time the exhaust gas passes through the control device. In some cases, the exhaust gas is cooled enough by the control device so these control devices have a greater potential for capturing condensable particulates than ones which do not reduce the temperature of the exhaust gas. Particulate matter control methods which use water may also be effective at capturing particulates which are soluble in water.

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5.2.1 Identify all Available PM and PM_{10} Combustion Control Technologies

Possible PM and PM_{10} control technologies for natural gas-fired boilers were gathered from the *EPA Air Pollution Control Cost Manual*,[12] the RBLC and CA-BACT databases, a review of the literature of BACT analyses for similar sources, and a review of PM and PM_{10} pollutant control technologies from EPA's Clean Air Technology Center (CATC) webpage.[13] The potential control technologies for particulate emissions are the following:

- Good Combustion Practices
- Clean Fuels
- Fabric Filter (Baghouse)
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator (WESP)
- Mechanical Collectors (such as Cyclones)
- Wet Scrubber

Table 5-4 summarizes the PM and PM_{10} BACT emission limits for new and modified natural gas-fired boilers in the RBLC and CA-BACT control technology databases. Data from the RBLC database indicate that the only particulate control technologies selected as BACT for new and modified natural gas-fired boilers include GCP and the use of clean fuels including natural gas. Emission limits range from 0.002 to 0.02 lb/MMBtu for natural gas combustion. Many of the emission limits in these tables were expressed as pounds per hour in the original database searches, but were converted to lb/MMBtu to make the emission limits comparable.

For the RBLC searches, the EPA database was queried for natural gas combustion (primarily RBLC codes 11.310 for > 250 MMBtu/hr and 12.310 for 100 – 250 MMBtu/hr) for the lowest particulate emission rates and the subsequent results were culled so that only boilers with ratings greater than 100 MMBtu/hr (roughly ½ the size of the Solvay boiler) and less than 500 MMBtu/hr (roughly twice the size of the Solvay boiler) were included. Searches which provided non-boiler emission sources such as duct burners at power plants were removed so that only boiler-type sources were included. In addition, the RBLC lowest limit searches were supplemented with recent BACT determinations research which was performed for similar package boilers. Only limits used for BACT determinations, and not "case-by-case" or "other" determinations are considered for the listings in Table 5-4.

There are no CA-BACT listings for particulate controls for boilers rated between 100 MMBtu/hr and 500 MMBtu/hr.

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[12] EPA, document no. EPA/452/B-02-001: *EPA Air Pollution Control Cost Manual*, Sixth Edition, January 2002.

[13] EPA CATC webpage: http://www.epa.gov/ttn/catc/products.html

Table 5-4. PM and PM_{10} Control Determinations for Natural Gas-Fired Boilers from RBLC

RBLC ID	RBLC Process Type	Facility	Permit Date	Process	Throughput (MMBtu/hr)	Controls	BACT Limit (lb/MMBtu)
WV-0023	12.310	Longview Power, LLC - Maidsville	03/02/04	Auxiliary Boiler	225.0	GCP, Clean Fuels	0.0022
OR-0040	13.310	Klamath Generation, LLC	03/12/03	Auxiliary Boiler			0.0042
TX-0293	11.310	Gregory Power Partners LP	06/16/99	Auxiliary Boiler	405.0	Natural Gas	0.0049
AR-0026	12.310	Pine Bluff Energy LLC-Pine Bluff Energy Center	05/05/09	Boiler	362.0	GCP, Clean Fuels	0.0050
AR-0057	12.310	Tenaska Arkansas Partners, LP	10/09/01	Boiler	122.0	GCP	0.0050
TX-0499	12.310	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175.0		0.0050
AL-0160	11.310	Mobile Energy LLC	06/07/00	Boiler	378.0	GCP	0.0050
LA-0229	12.310	Shintech Louisiana Plaquemine Plant 2	07/10/08	Utility Boilers	250.0	GCP, Clean Fuels	0.0050
IA-0088	11.310	Archer Daniels Midland	06/29/07	2 Boilers	292.5	Natural Gas	0.0050
SC-0071	11.310	Columbia Energy Center	04/09/01	2 Auxiliary Boilers	350.0	GCP	0.0050
SC-0061	11.310	Columbia Energy LLC	04/09/01	Boiler	350.0	Clean Fuels	0.0051
ID-0017	12.310	SE Idaho Power County Energy Center	02/10/09	Package Boiler	250.0	GCP	0.0052
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	134.0	None Listed	0.0052
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	152.0	None Listed	0.0052
NJ-0036	12.310	AES Red Oak, LLC	10/24/01	Auxiliary Boiler	120.0	GCP	0.0066
TX-0414	12.310	Atofina Petrochemicals Port Arthur Complex	04/22/99	Supplement Boiler	227.0	Low Ash Fuel	0.0070
OH-0269	11.310	Biomass Energy	01/05/04	Auxiliary Boiler	247.0		0.0070
OH-0307	11.310	Biomass Energy	04/04/06	Auxiliary Boiler	247.0		0.0070
TX-0414	12.310	Fina Oil & Chemical Company	04/22/99	Boiler	227.0	Low Ash Fuel	0.0070
NC-0101	12.310	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.0	GCP	0.0074
IN-0085	12.310	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125.0	GCP	0.0074
TX-0511	11.310	BASF Fina Petrochemicals	02/03/06	2 Boilers	425.4		0.0075
LA-0254	11.310	Entergy Louisiana LLC	08/16/11	Auxiliary Boiler	338.0	GCP	0.0075
WI-0228	12.310	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230.0	GCP, Natural Gas	0.0075
TN-0153	12.310	Williams Refining & Marketing, LLC	04/03/02	Boiler	180.0		0.0075
CO-0041	11.310	American Soda LLP, Pineance Facility	05/06/99	2 Boilers	258.7	GCP	0.0075
OH-0310	12.310	American Municipal Power Generating Station	02/07/08	Auxiliary Boiler	150.0		0.0076
MS-0069	12.310	Dupont Delisle Facility	06/08/04	Boiler	231.0	Natural Gas	0.0076
IA-0067	11.310	Midamerican Energy Company	06/17/03	Auxiliary Boiler	429.4	GCP	0.0076
VA-0278	12.310	Virginia Commonwealth University East Plant	03/31/03	3 Boilers	151.0		0.0080
AL-0128	12.310	Alabama Power Co. - Theodore Cogeneration	03/16/99	Boiler	220.0	Natural Gas	0.0080
VA-0270	12.310	Virginia Commonwealth University East Plant	03/31/03	Boiler	150.0	GCP	0.0080
MN-0039	12.310	Minnesota Corn Processors	08/08/00	Boiler	237.0	Natural Gas	0.0084
TX-0310	11.310	The Goodyear Tire & Rubber Company	01/06/99	Boiler	264.0		0.0100
ND-0025	11.310	Tharaldson Ethanol Plant 1, LLC	12/20/07	Boiler	480.0		0.0138
TX-0416	11.310	Shell Oil Company	11/24/99	Boiler	357.0	Low Sulfur Fuel	0.0149
MA-0037	12.310	University of Massachusetts Bldg. Authority	10/29/08	Boilers	162.0		0.0200
TX-0419	11.310	Calpine Construction Finance CO., LP	03/22/00	3 Auxiliary Boilers	380.0	Low Ash Fuel	0.0200

Fabric Filter (Baghouse): In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing the PM in the flue gas to be collected on the fabric by sieving or other mechanisms. Fabric filers may be in the form of sheet, cartridges, or bags, with a number of the individual fabric filter units housed together as a group. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags.

Typical new equipment design efficiencies are between 99 and 99.9%. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and cleaning mechanism. In general, collection efficiency increases with increasing filtration velocity and particle size. [14] Reduced efficiencies will occur when the inlet particle concentration is low. Baghouse controls do not significantly affect the temperature of the stream being treated; so, condensable particulate matter control is limited to condensable particulates present in a filterable form in the baghouse when it is being treated.

The main operating limitation of a baghouse is that its operating temperature is limited by the bag/filter material which usually can tolerate exhaust streams no hotter than about 200 ºF – 300 º F.

Dry Electrostatic Precipitator (ESP): An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust-handling system, such as a pneumatic conveyor, and then is disposed of in an appropriate manner.

Typical new equipment design efficiencies are between 99 and 99.9%. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. While several factors determine ESP collection efficiency, ESP size is most important. Size determines the treatment time; the longer the particle spends in the ESP, the greater its chance of being collected. Maximizing electric field strength will maximize ESP collection efficiency. Collection efficiency is also affected by dust resistivity, gas temperature, chemical composition (of the dust and gas), and particle size distribution. ESPs can operate at very high temperatures, as high as 1300ºF. [15]

Wet Electrostatic Precipitator (WESP): The principle operation of the wet ESP is similar to a dry ESP. However, with wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The collection hoppers used by dry ESPs are replaced by a drainage system for wet ESPs. The wet effluent is collected, and often treated on-site.

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[14] EPA, document no. EPA-452/F-03-025: *Air Pollution Control Technology Fact Sheet – Fabric Filter – Pulse-Jet Cleaned Type (Also referred to as Baghouses)*, http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf

[15] EPA, document no. EPA-452/F-03-028: *Air Pollution Control Technology Fact Sheet – Dry Electrostatic Precipitator (ESP) – Wire-Plate Type,* http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf

Typical new equipment design efficiencies for WESP are between 99 and 99.9%. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. WESP can collect sticky particles and mists, as well as highly resistive or explosive dusts. The continuous or intermittent washing with a liquid eliminates the reentrainment of particles due to rapping which dry ESPs are subject to. Wet plate ESPs are limited to operating temperatures lower than approximately 170 ºF to 190 ºF. [16]

Mechanical Collectors (such as Cyclones): Mechanical collectors use a variety of mechanical forces to collect particulate matter: inertial separators use inertia and gravity to remove the larger particles from the smaller particles. Cyclones use centrifugal force to separate particulate matter from gas streams.

Drop out boxes are typically used as inertial separators. Larger particles are trapped in drop out boxes as the inertia they contain forces them to go straight as the rest of the gas stream turns to flow into and out of the drop out box. Particles are also removed by gravitational settling in the drop out box. Inertial separators can only remove the larger dust particles (>75 microns). They are typically used upstream of other control devices in high inlet dust loading cases.

Cyclone separators are designed to remove particles by inducing a vortex as the gas stream enters the chamber, causing the exhaust gas stream to flow in a spiral pattern. Centrifugal forces cause the larger particles to concentrate on the outside of the vortex and consequently slide down the outer wall and fall to the bottom of the cyclone, where they are removed. The cleaned gas flows out of the top the cyclone. Control efficiency ranges for single cyclones are often based on three classifications of cyclone (conventional, high-efficiency, and high-throughput). The control efficiency ranges for conventional single cyclones is estimated to be 70 to 90 for PM, 30 to 90 percent for PM_{10}, and 0 to 40 percent for $PM_{2.5}$. High efficiency single cyclones are designed to achieve higher control of smaller particles than conventional cyclones and have control efficiency ranges estimated to be 80 to 99 for PM, 60 to 95 percent for PM_{10}, and 20 to 70 percent for $PM_{2.5}$. High throughput cyclones are only guaranteed to remove particles greater than 20 micrometers, although collection of smaller particles does occur to some extent; their control efficiency ranges are 80 to 99 for PM, 10 to 40 percent for PM_{10}, and 0 to 10 percent for $PM_{2.5}$.[17]

Wet Scrubber: Wet scrubbers, also termed particulate scrubbers, remove particles from waste gas by capturing the particles in liquid droplets and separating the droplets from the gas stream. The droplets transport the particulate out of the gas stream. Scrubbers may capture particulates through the following mechanisms: impaction of the particle directly into a target droplet; interception of the particle by a target droplet as the particle comes near the droplet; diffusion of the particle through the gas surrounding the target droplet until the particle is close enough to be captured.

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[16] EPA, document no. EPA-452/F-03-028: *Air Pollution Control Technology Fact Sheet – Dry Electrostatic Precipitator (ESP) – Wire-Plate Type,* http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf

[17] EPA, document no. EPA-452/F-03-005: *Air Pollution Control Technology Fact Sheet – Cyclones,* http://www.epa.gov/ttn/catc/dir1/fcyclon.pdf

Scrubbers are generally classified according to the liquid contacting mechanism used. The most common scrubber designs are spray-chamber scrubbers, cyclone spray chambers, orifice and wet impingement scrubbers, and venturi scrubbers.

Venturi scrubber PM control efficiencies range from 70 to greater than 99 percent, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 to 5 micrometers.

5.2.2 Eliminate Technologically Infeasible Technologies

Based on a BACT review of a similar gas-fired boiler[18], all of the identified PM and PM_{10} control technologies, including fabric filter baghouses, dry ESPs, wet ESPs, wet scrubbers, and mechanical collectors are technically feasible technologies for natural gas-fired boilers. However, none of these technologies have been required as BACT for new or modified natural gas–fired boilers. This is because natural gas has almost no inert materials or ash, so that the "uncontrolled" PM and PM_{10} emissions from the combustion of these fuels is as low as the controlled PM emission rate from solid fuel combustion using state-of-the art air pollution control systems like fabric filter baghouses and ESPs.

For example, PM and PM_{10} emissions from natural gas combustion are primarily condensable particulates which are not readily removed by add-on PM control devices. From the boiler calculations in Appendix D: , the estimated hourly PM and PM_{10} emissions for the Solvay boiler using AP-42 emission factors are 1.42 lb/hr for condensable PM and 0.47 lb/hr for filterable PM for a total of 1.89 lb/hr total PM. The concentrations for the filterable portion of PM (i.e., the portion which could theoretically be captured by potential add-on controls) from the Solvay gas-fired boiler is around 0.0013 gr/dscfm (0.47 lb/hr x 7000 gr/lb / 42,691 dscf/min x 60 min/hr) which is much less than a controlled PM and PM_{10} emission rate of 0.005 gr/dscfm from state-of-the art controls such as fabric filter baghouses or ESPs.

As a result, for natural gas combustion, none of the control technologies are expected to achieve emission rates lower than the use of natural gas fuel and good combustion practices designed to minimize products of incomplete combustion. The natural gas combustion emission rate for PM and PM_{10} is expected to be 0.0075 lb/MMBtu (1.893 lb/hr total condensable and filterable PM and PM_{10} emissions from AP-42 for gas-fired boilers divided by 254 MMBtu/hr rating of Solvay boiler).

5.2.3 Rank the Remaining Technologies by Control Effectiveness

Solvay is not aware of the use of any post-combustion particulate control systems on any natural gas-fired boiler. Therefore, the highest ranked or most effective PM/PM_{10} control technology for the natural gas-fired boilers is the use of natural gas as the fuel.

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[18] We Energies, Rothschild, Wisconsin: http://www.nobiomassburning.org/OLD/BAP/Ash_files/We%20Energies%20air_permit_application.pdf

5.2.4 Evaluate the Most Effective Control Based on a Case-by-Case Consideration of Energy, Environmental, and Economic Impact; Then Select the PM and PM_{10} BACT

Consistent with recent BACT determinations, GCP and the firing of natural gas are selected as BACT for PM and PM_{10} control for Solvay's natural-gas fired boiler. None of the recent PM and PM_{10} BACT determinations for the natural-gas fired boiler source category utilized add-on controls for PM and PM_{10}.

Solvay proposes a BACT PM and PM_{10} emission limit of 0.0075 lb/MMBtu (based on AP-42 emission factors) when firing natural gas which is consistent with recent BACT determinations for natural gas-fired boilers.

5.3 BACT Review – $PM_{2.5}$ Emissions

The BACT review process described in Section 5.0 is applied to potential $PM_{2.5}$ emission controls for Solvay's new natural-gas fired package boiler in this subsection.

Fine particles in the atmosphere are made up of a complex mixture of components. Common constituents include sulfate (SO_4); nitrate (NO_3); ammonium; elemental carbon; a great variety of organic compounds; and inorganic material (including metals, dust, sea salt, and other trace elements) generally referred to as ''crustal'' material, although it may contain material from other sources. Airborne PM with a nominal aerodynamic diameter of 2.5 micrometers or less are considered to be ''fine particles,'' and are also known as $PM_{2.5}$. ''Primary'' particles (also referred to as direct emissions) are emitted directly into the air as a solid or liquid particle (*e.g.*, elemental carbon from diesel engines or fire activities, or condensable organic particles from gasoline engines). ''Secondary'' particles (*e.g.*, sulfate and nitrate) form in the atmosphere as a result of various chemical reactions.

Fuel combustion, including natural gas, results in primary/direct emissions of $PM_{2.5}$. Direct emissions of $PM_{2.5}$ from natural gas combustion have been estimated to be less than one micrometer in size and include both solid or filterable $PM_{2.5}$, and condensable or back half $PM_{2.5}$. Because natural gas is a gaseous fuel, filterable PM emissions are typically low.

Scientific research has shown that various pollutants can contribute to ambient $PM_{2.5}$ concentrations. In addition to primary/direct $PM_{2.5}$ emissions, EPA has identified SO_2, NOx, VOC, and ammonia as $PM_{2.5}$ precursors which contribute to secondary formation of $PM_{2.5}$. These gas-phase precursors undergo chemical reactions in the atmosphere to form secondary $PM_{2.5}$. Formation of secondary $PM_{2.5}$ depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity; and the interactions of precursors with preexisting particles and with cloud or fog droplets.

On May 16, 2008, EPA finalized rules to implement the New Source Review (NSR) program (40 CFR 51 and 52) for $PM_{2.5}$. These rules are incorporated in WAQSR, Chapter 6, Section 4(a) under the definitions of "Regulated NSR Pollutant" and "Significant". The significant emission rates for $PM_{2.5}$ are: 10 tpy of direct $PM_{2.5}$ emissions, 40 tpy of SO_2 emissions, and 40 tpy of NOx emissions, unless not demonstrated to be a $PM_{2.5}$ precursor by the

State. NOx are presumed to be precursors to $PM_{2.5}$ in all attainment and unclassifiable areas, unless the State demonstrates to the EPA Administrator's satisfaction or EPA demonstrates that emissions of nitrogen oxides from sources in a specific area are not a significant contributor to that area's ambient $PM_{2.5}$ concentrations. VOC are presumed not to be precursors to $PM_{2.5}$ in any attainment or unclassifiable area, unless the State demonstrates to the EPA Administrator's satisfaction or EPA demonstrates that emissions of VOC from sources in a specific area are a significant contributor to that area's ambient $PM_{2.5}$ concentrations. According to EPA, due to the considerable uncertainty related to ammonia as a precursor, the final rules do not require ammonia to be regulated as a $PM_{2.5}$ precursor, but do give States the option to regulate ammonia as a precursor to $PM_{2.5}$ in nonattainment areas for purposes of NSR on a case-by-case basis. Thus, ammonia is presumed not to be regulated per the $PM_{2.5}$ NSR rule and is not incorporated in the WAQSR.

As described in Section 3.1 and shown on Table 3-2, Solvay's proposed gas-fired boiler and debottlenecked sources result in direct $PM_{2.5}$ emissions of 50.2 tpy, NOx emissions of 101.4 tpy, and SO_2 emissions of 0.8 tpy (0.7 tpy from package boiler). Thus, the project triggers PSD for $PM_{2.5}$, based on direct $PM_{2.5}$ and NOx as a precursor, but not due to SO_2 as a precursor. Under the $PM_{2.5}$ PSD program, BACT applies to direct $PM_{2.5}$ emissions; SO_2 emissions; NO_X emissions, unless a State demonstrates that NOx is not a significant contributor to ambient $PM_{2.5}$ concentrations in that area; and to VOC if identified by a State as a precursor in the $PM_{2.5}$ attainment area where the source is located.[19] Based on the definition of "Significant" (in context of $PM_{2.5}$ emissions) in WAQSR, Chapter 6, Section 4(a), it is assumed that $PM_{2.5}$ precursors applicable to the proposed gas-fired boiler at Solvay are NO_x and SO_2.

Note that this BACT analysis already includes a complete control technology review for NO_x. Therefore, further analysis of NO_x as a $PM_{2.5}$ precursor is unnecessary. In addition, SO_2 emissions from the project are insignificant and recent BACT determinations for similar natural gas-fired boilers have concluded that GCP and burning of clean fuels (i.e., natural gas) are BACT for SO_2[20] so further analysis of SO_2 as a $PM_{2.5}$ precursor is not performed here – utilization of natural gas fuel with GCP is presumed BACT for Solvay's new boiler for $PM_{2.5}$.

5.3.1 Identify all Available $PM_{2.5}$ Combustion Control Technologies

Data from the RBLC database indicate that the only PM and PM_{10} control technologies selected as BACT for new natural gas-fired boilers include good combustion practices and the use of clean fuels including natural gas. Other PM controls include fabric filter baghouses, electrostatic precipitators (wet and dry versions), mechanical collectors such as multicyclones, and wet scrubbers as described in Section 5.2.1. These control technologies are considered here for the BACT analysis of $PM_{2.5}$. Solvay has not identified any additional control technologies applicable to $PM_{2.5}$ in addition to those identified in the PM and PM_{10} BACT analysis.

A search of the RBLC database to find the lowest emission rate for RBLC categories 11.310 and 12.310 did not produce any BACT determinations for $PM_{2.5}$. Through another search means of the RBLC, one facility was identified as having a BACT determination explicitly for $PM_{2.5}$ (RBLC ID: LA-0254, Entergy Louisiana LLC,

[19] Federal Register / Vol. 73, No. 96 / Friday, May 16, 2008, page 28343.

[20] We Energies, Rothschild, Wisconsin: http://www.nobiomassburning.org/OLD/BAP/Ash_files/We%20Energies%20air_permit_application.pdf

8/16/2011) with a limit of 7.6 lb/MMscf which is equivalent to 0.0075 lb/MMBtu (i.e., 7.6 MMscf / 1020 MMBtu/MMscf natural gas thermal equivalent). This value is consistent with the AP-42 emission factor (Table 1.4-2) for total particulates and is based on GCP.

5.3.2 Eliminate Technologically Infeasible Technologies

Based on BACT reviews of similar gas-fired boilers and consistent with the BACT in this report for PM and PM_{10}, all of the identified PM and PM_{10} control technologies, including fabric filter baghouses, dry ESPs, wet ESPs, wet scrubbers, and mechanical collectors are technically feasible $PM_{2.5}$ control technologies for natural gas-fired boilers. However, none of these technologies have been required as BACT for new or modified natural gas–fired boilers.

Consistent with the conclusions made for PM and PM_{10}, for natural gas combustion, none of the PM control technologies are expected to achieve emission rates lower than the use of natural gas fuel and good combustion practices designed to minimize products of incomplete combustion. Further, because of the very low expected $PM_{2.5}$ emission rates from the combustion of natural gas, there is no basis to conclude that post combustion PM controls would actually result in reductions in $PM_{2.5}$ emissions. The natural gas combustion emission rate for $PM_{2.5}$ is expected to be 0.0075 lb/MMBtu (1.893 lb/hr total condensable and filterable PM emissions from AP-42 for gas-fired boilers divided by 254 MMBtu/hr rating of Solvay boiler).

5.3.3 Rank the Remaining Technologies by Control Effectiveness

The combustion of only natural gas combined with GCP is expected to achieve an emission rate of 0.0075 lb/MMBtu for $PM_{2.5}$. This is the highest ranked level of control.

5.3.4 Evaluate the Most Effective Control Based on a Case-by-Case Consideration of Energy, Environmental, and Economic Impact; Then Select the $PM_{2.5}$ BACT

None of the recent $PM/PM_{10}/PM_{2.5}$ BACT determinations for the natural-gas fired boiler source category utilized add-on controls for PM. Therefore, GCP and the firing of natural gas are selected as BACT for $PM_{2.5}$ control for Solvay's natural-gas fired boiler.

Solvay proposes a BACT $PM_{2.5}$ emission limit of 0.0075 lb/MMBtu when firing natural gas which is consistent with recent BACT determinations for natural gas-fired boilers.

5.4 BACT Review – CO Emissions

The BACT review process described in Section 5.0 is applied to potential CO emission controls for Solvay's new natural-gas fired package boiler in this subsection.

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion since CO is emitted from natural gas-fired boilers as a result of incomplete combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. CO emissions can be reduced by operating the boiler with higher furnace temperatures, higher excess oxygen levels, and longer furnace residence times. However, techniques for reducing CO emissions can result in an increase in NOx emissions. Thus, achieving low CO and low NOx emissions is a balancing act in both boiler design and operation.

5.4.1 Identify all Available CO Combustion Control Technologies

Possible CO control technologies for natural gas-fired boilers were gathered from the *EPA Air Pollution Control Cost Manual*,[21] the RBLC and CA-BACT databases, a review of the literature of BACT analyses for similar sources, and a review of CO pollutant control technologies from EPA's Clean Air Technology Center (CATC) webpage.[22] These available control technologies include the following: combustion controls (GCP), flares, afterburning, thermal oxidation, and catalytic oxidation.

Table 5-5 summarizes the CO BACT emission limits for new and modified natural gas-fired boilers in the RBLC and CA-BACT control technology databases. Emission limits range from 0.016 to 0.18 lb/MMBtu for natural gas combustion. Many of the emission limits in these tables were expressed as pounds per hour in the original database searches, but were converted to lb/MMBtu to make the emission limits comparable.

The technologies identified in these databases include GCP and oxidation catalysts in one instance. Note that only one BACT determination entry from the RBLC database search, Calpine Turner Energy Center, indicated that oxidation catalyst add-on controls (i.e., catalytic oxidation) was considered BACT. However, the RBLC includes a note on Calpine Turner Energy Center stating, "Facility will never be built. Did not receive a site certificate from the Oregon Energy Facility Siting Council." In addition, as described in Section 5.4.2 catalytic oxidation is not considered technologically feasible for package boilers.

For the RBLC searches, the EPA database was queried for natural gas combustion (primarily RBLC codes 11.310 for > 250 MMBtu/hr and 12.310 for 100 – 250 MMBtu/hr) for the lowest CO emission rates and the subsequent results were culled so that only boilers with ratings greater than 100 MMBtu/hr (roughly ½ the size of the Solvay boiler) and less than 500 MMBtu/hr (roughly twice the size of the Solvay boiler) were included. Searches which provided non-boiler emission sources such as duct burners at power plants were removed so that only boiler-type sources were included. Only limits used for BACT determinations, and not "case-by-case" or "other" determinations are considered for the listings in Table 5-5.

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[21] EPA, document no. EPA/452/B-02-001: *EPA Air Pollution Control Cost Manual*, Sixth Edition, January 2002.

[22] EPA CATC webpage: http://www.epa.gov/ttn/catc/products.html

There is one CA-BACT listing for boilers between 100 MMBtu/hr and 500 MMBtu/hr (Darling International Inc., 110 MMBtu/hr gas-fired boiler) with a CO limit of 100 ppmvd at 3% oxygen. The control technology preference for this listing was not provided, but the NOx is controlled by LNB-FGR for this facility, so it is assumed that the control technology for CO control is GCP, not add-on controls such as oxidation catalysts.

Table 5-5. CO Control Determinations for Natural Gas-Fired Boilers from RBLC

RBLC ID	RBLC Process Type	Facility	Permit Date	Process	Throughput (MMBtu/hr)	Controls	BACT Limit (lb/MMBtu)
AZ-0046	11.310	Arizona Clean Fuels Yuma LLC	04/14/05	2 Boilers	419.0		0.016
TX-0499	12.310	Sandy Creek Energy Associates	07/24/06	Auxiliary Boiler	175.0		0.035
OR-0040	13.310	Klamath Generation	03/12/03	Auxiliary Boiler			0.035
TX-0511	11.310	BASF Fina Petrochemicals	2/3/2006	2 Boilers	425.4		0.035
LA-0229	12.310	Shintech Louisiana Plaquemine Plant 2	07/10/08	Utility Boilers	250.0	GCP	0.036
GA-0127	12.310	Southern Company Plant Mcdonough	01/07/08	Auxiliary Boiler	200.0		0.037
OR-0046	12.310	Calpine Turner Energy Center	01/06/05	Auxiliary Boiler	139.3	OC	0.038
CO-0052	12.310	Rocky Mountain Energy Center.	08/11/02	Auxiliary Boiler	129.0	GCP	0.039
MN-0062	12.310	Heartland Corn Products	12/22/05	Boiler	198.0		0.040
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	118.0		0.040
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	134.0		0.040
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	152.0		0.040
WV-0023	12.310	Longview Power	03/02/04	Auxiliary Boiler	225.0	GCP	0.040
AR-0026	12.310	Pine Bluff Energy Center	05/05/99	Boiler	362.0	GCP	0.044
WA-0301	11.310	British Petroleum	04/20/05	Boiler	363.0	GCP	0.050
AL-0160	11.310	Mobile Energy LLC	06/07/00	Boiler	378.0	GCP	0.050
NJ-0036	12.310	AES Red Oak, LLC	10/24/01	Auxiliary Boiler	120.0	GCP	0.050
SC-0061	11.310	Columbia Energy LLC	04/09/01	2 Boilers	350.0	GCP	0.060
SC-0071	11.310	Columbia Energy Center	04/09/01	2 Auxiliary Boilers	350.0	GCP	0.060
TX-0419	11.310	Calpine Construction Finance Co., LP	03/22/00	3 Auxiliary Boilers	380.0	GCP	0.069
TX-0414	12.310	Fina Oil & Chemical Company	04/22/99	Boiler	227.0	GCP	0.069
IA-0088	11.310	Archer Daniels Midland	06/29/07	2 Boilers	292.5	GCP	0.072
ID-0017	12.310	Southeast Idaho Advanced Energy Center	02/10/09	Package Boiler	250.0	GCP	0.074
TX-0416	11.310	Shell Oil Company	11/24/99	Boiler	357.0	GCP	0.079
MN-0066	12.310	Northern States Power Riverside Plant	05/16/06	Auxiliary Boiler	160.0	GCP	0.080
WI-0228	12.310	Wisconsin Public Service - Weston	10/19/04	Auxiliary Boiler	229.8	GCP	0.080
IN-0085	12.310	PSEG Lawrenceburg Energy	06/07/01	Auxiliary Boiler	124.6	GCP	0.082
LA-0254	11.310	Entergy Louisiana LLC	08/16/11	Auxiliary Boiler	338.0	GCP	0.082
NC-0101	12.310	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.2	GCP	0.082
IA-0067	11.310	Midamerican Energy Company	06/17/03	Auxiliary Boiler	429.4	GCP	0.084
OH-0310	12.310	American Municipal Power	10/08/09	Auxiliary Boiler	150.0		0.084
TX-0371	11.310	Corpus Christi Cogen LP	02/04/00	3 Auxiliary Boilers	315.0		0.089
CO-0041	11.310	American Soda LLP, Pineance Facility	05/06/99	2 Boilers	258.7	GCP	0.090
ND-0025	11.310	Tharaldson Ethanol Plant 1, LLC	12/20/07	Boiler	480.0		0.090
LA-0184	11.310	Louisiana Pigement Company, LP	05/13/03	2 Boilers	135.0	GCP	0.091
VA-0270	12.310	Virginia Commonwealth University	03/31/03	Boiler	150.0	GCP	0.099
VA-0278	12.310	Virginia Commonwealth University	03/31/03	3 Boilers	150.8	GCP	0.099
AL-0199	11.310	Weyerhaeuser Company	11/15/02	Boiler	300.0		0.100
LA-0124	11.310	PPG Industries	11/23/99	2 Boilers	356.0	GCP	0.100
AR-0057	12.310	Tenaska Arkansas Partners, LP	10/09/01	Boiler, (2)	122.0	GCP	0.110
OH-0269	11.310	Biomass Energy	01/05/04	Auxiliary Boiler	247.0		0.110
OH-0307	11.310	Biomass Energy	04/04/06	Auxiliary Boiler	247.0		0.110
TX-0310	11.310	The Goodyear Tire & Rubber Company	01/06/99	Boiler	264.0		0.135
NE-0013	11.310	Cargill, Inc.	09/30/99	Boiler	276.7	GCP	0.140
AL-0128	12.310	Alabama Power Co. - Theodore Cogeneration	03/16/99	Boiler	220.0	GCP	0.165
TN-0153	12.310	Williams Refining and Marketing, LLC	04/03/02	Boiler, No. 10	180.0		0.180
TX-0293	11.310	Gregory Power Partners LP	06/16/99	2 Auxiliary Boilers	405.0		100 ppm @ 3% O2

GCP = Good Combustion Practices, OC = Oxidation Catalyst

Combustion Controls

Combustion controls are also referred to as good combustion practices which include good burner design, optimizing the air and fuel flow rates to the boiler, sufficiently high temperatures, and good maintenance practices. Implementing proper control for air and fuel flow rates ensures that there will be adequate gas residence time, suitable temperature profiles, and sufficient combustion zone turbulence to promote maximum oxidation which results in minimum generation of CO. Proper operation and maintenance of the combustion system helps to minimize the formation and emission of CO by ensuring that the system operates as designed. Examination of the RBLC database indicates that implementation of good combustion practices to minimize CO is the most commonly applied BACT measure for natural gas-fired boilers.

Add-on Controls

Add-on controls are post-combustion technologies that operate to reduce the level of CO in the flue gas and include the following:

Flares: Flares are commonly used in the control of organic-laden slipstreams from refineries and other chemical manufacturing processes with sufficient heating values. A flare operates by continuously maintaining a pilot flame, typically with natural gas. When a combustible exhaust stream is vented to a flare, the exhaust stream is ignited by the pilot flame at the flare tip, and combustion occurs in the ambient air above the flare.

Afterburning: Afterburners oxidize CO into CO_2 from a process where combustion is incomplete by utilizing gas burners to bring the temperature of the exhaust stream up to a temperature to promote complete combustion.

Thermal Oxidation: Thermal oxidation involves passing exhaust gases through a separate retention chamber in which CO emissions are oxidized. This type of technology is also referred to as External Thermal Oxidation (ETO) and requires heat and oxygen to convert CO in the flue gas to CO_2. There are two general types of ETO that are used for the control of CO emissions: regenerative thermal oxidization and recuperative thermal oxidization. The primary difference between regenerative and recuperative ETO is that regenerative ETO utilizes a combustion chamber and heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate heat exchanger to preheat incoming air prior to entering the combustion chamber.

EPA further categorizes regenerative ETO into two technology categories: a regenerative thermal oxidizer (RTO), or a regenerative catalytic oxidizer (RCO) if a catalyst is used.[23] According to EPA, RTO systems do not reduce the levels of CO, while RCO systems using precious-metal-based catalysts can destroy more than 98 percent of the CO in VOC-laden air streams.

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[23] EPA, document no. EPA-452/F-03-021: *Air Pollution Control Technology Fact Sheet – Regenerative Incinerator*, p. 1. http://www.epa.gov/ttn/catc/dir1/fregen.pdf

Catalytic Oxidation: A catalytic oxidizer converts the CO in the combustion gases to CO_2 at temperatures ranging from 600 °F to 800 °F in the presence of a catalyst.[24] Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device, such as an electrostatic precipitator; however, this would require reheating the exhaust gases to the required operating temperature for the catalytic process.

5.4.2 Eliminate Technologically Infeasible Technologies

Table 5-6 summarizes the feasibility of potential CO controls for natural gas-fired package boilers.

Table 5-6. Candidate CO Controls

Control Technology	Commercially Available	Technically Feasible?
Combustion Controls	Available	Feasible
Flares	Not demonstrated for natural gas-fired boiler CO controls	Infeasible
Afterburning	Not demonstrated for natural gas-fired boiler CO controls	Infeasible
Thermal Oxidation	Not demonstrated for natural gas-fired boiler CO controls	Infeasible
Catalytic Oxidation	Not demonstrated for natural gas-fired package boiler CO controls	Infeasible

Combustion Controls: Combustion controls, which include furnace and combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of CO emissions. These technologies have been widely demonstrated in similar applications to generate significantly lower levels of CO emissions when compared to boilers designed, operated, and maintained without regard to CO emissions. Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for coal-fired boiler CO emissions control. Therefore, combustion controls are considered technically feasible.

Flares: Flares are commonly used in the control of organic slipstreams from refineries and other chemical manufacturing processes with sufficient heating value. Based on a review of the RBLC database and a survey of air permits for natural gas-fired boilers, flares have not been demonstrated for natural gas-fired boiler CO emission control. Therefore, an assessment of the availability and applicability of this technology was conducted to determine if it is technically feasible.

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[24] EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet – Catalytic Incinerator*, p. 3. http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

The heating value of the natural gas-fired-boiler exhaust gases is essentially zero, far below the necessary waste gas stream heating value for flares (e.g., 300 Btu/scf).[25] Since the natural gas-fired boiler exhaust will not have sufficient heating value for flaring and since flares have not been applied for natural gas-fired boiler emissions control, flares are not considered an applicable technology for CO emissions control. Therefore, flares are determined to be technically infeasible.

Afterburners: Based on a review of the RBLC database and a survey of air permits for natural gas-fired boilers, afterburners have not been demonstrated for natural gas-fired boiler CO emission control. Therefore, an assessment of the availability and applicability of this technology was conducted to determine if it is technically feasible.

The term "afterburner" is generally appropriate only to describe a thermal oxidizer used to control gases coming from a process where combustion is incomplete.[26] Since the natural gas-fired boilers will be carefully tuned to maximize fuel combustion efficiency (subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in near- complete combustion. Therefore, additional afterburner combustion would not be expected to provide any useful benefit. Since afterburners are not applicable for natural gas-fired boiler CO emissions control, afterburners are determined to be technically infeasible.

Thermal Oxidation: Thermal incinerators can be used to reduce emissions from almost all VOC sources, including solvent operations, and operations performed in ovens, dryers, and kilns. ETO is generally utilized for controlling CO, VOC, or organic HAP (Hazardous Air Pollutants) emissions from high-concentration, non-combustion sources (e.g., surface coating operations and chemical plants). Based on a review of the RBLC database and a survey of air permits for natural gas-fired boilers, regenerative thermal oxidation and recuperative thermal oxidation have not been demonstrated for use on natural gas-fired boilers. Therefore, an assessment of the availability and applicability of this technology was conducted to determine if it is technically feasible.

ETO is not applicable for boiler CO emissions control for the same reason that afterburners are not applicable. Since the boilers will be carefully tuned to maximize fuel combustion efficiency (subsequently minimizing CO emissions) while minimizing NO_X formation, the process will result in essentially complete combustion. Therefore, additional thermal oxidation would not be expected to provide any useful benefit (the boiler serves as a thermal oxidizer where high combustion efficiency is a primary concern), and ETO is determined to be not applicable.

Based on a review of BACT analyses for similar boilers, thermal oxidation has never been required nor used on a natural gas-fired boiler, and its theoretical ability to reduce CO emissions from these boilers is questionable. Thermal oxidation would involve injecting additional air into the flue gas and heating the oxygen enriched mixture to oxidize CO to carbon dioxide. However, since the combustion of the reheat fuel would itself result in

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[25] EPA, document no. EPA-452/F-03-019: *Air Pollution Control Technology Fact Sheet – Flare*, p. 2. http://www.epa.gov/ttn/catc/dir1/fflare.pdf

[26] EPA, document no. EPA-452/F-03-022: *Air Pollution Control Technology Fact Sheet – Thermal Incinerator*, p. 1. http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

CO emissions, there is no evidence that thermal oxidation would result in any CO emission reductions. Since thermal oxidation has never been demonstrated on a natural gas-fired boiler, and because there is no evidence that it could reduce CO emissions, thermal oxidation is not considered a technically feasible CO control technology.[27]

Catalytic Oxidation: Catalytic incinerators can be used to reduce emissions of CO, VOC, and organic HAP emissions from a variety of stationary sources, including the following:[28]

- Surface coating and printing operations
- Varnish cookers
- Foundry core ovens
- Filter paper processing ovens
- Plywood veneer dryers
- Gasoline bulk loading stations
- Chemical process vents
- Rubber products and polymer manufacturing
- Polyethylene, polystyrene, and polyester resin manufacturing

Catalytic oxidation has been used to control CO emissions from natural-gas-fired combustion turbine exhaust streams (which exhibit much higher levels of products of incomplete combustion than steam boilers) since oxidation catalysts are suitable for gas streams with negligible particulate loading. However, for similar BACT determinations of auxiliary package boilers, catalytic oxidation has been considered technically infeasible.[29] Industrial package boilers are pre-assembled units that are delivered to the site as a prefabricated unit. Due to shipping size constraints, package boilers are very compact. The small furnace volumes of package boilers preclude application of a number of control alternatives that may be applied to field-erected boilers, which typically are constructed with large furnace volumes.

The oxidation catalyst must be placed within a section of the furnace where the flue gas temperature is consistently 600 °F to 800 °F in the presence of a catalyst.[30] Further, the catalyst bed requires a large surface area (as in the full-height heat recovery steam generator of a combined cycle turbine) to limit velocity of the flue

[27] We Energies, Rothschild, Wisconsin:
http://www.nobiomassburning.org/OLD/BAP/Ash_files/We%20Energies%20air_permit_application.pdf

[28] EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet – Catalytic Incinerator*, p. 3. http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

[29] Duke Energy, Cliffside Steam Station, North Carolina:
http://daq.state.nc.us/permits/psd/docs/cliffside/Top-down_BACT_for_Auxiliary_Boiler_%209-19-06.pdf

[30] EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet – Catalytic Incinerator*, p. 3. http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

gases across the catalyst bed and to limit adverse pressure drop. The application of oxidation catalyst technology within the compact design of a package boiler is concluded to be not technically feasible.

Note that only one BACT determination entry from the RBLC database search (see Table 5-5), Calpine Turner Energy Center, indicated that add-on controls (oxidation catalyst; i.e., catalytic oxidation) were considered BACT for an "auxiliary boiler." However, the RBLC includes a note on this facility stating, "Facility will never be built. Did not receive a site certificate from the Oregon Energy Facility Siting Council." Solvay is not aware of any BACT determinations which utilize oxidation catalysts for CO control from package boilers.

Therefore, Solvay is has not identified any add-on CO controls which have been applied as BACT to natural-gas fired package boilers.

5.4.3 Rank the Remaining Technologies by Control Effectiveness

The only remaining technically feasible CO control technology is GCP.

5.4.4 Evaluate the Most Effective Control Based on a Case-by-Case Consideration of Energy, Environmental, and Economic Impact; Then Select the CO BACT

GCP are selected as BACT for CO control for Solvay's natural-gas fired boiler and these conclusions are consistent with recent BACT determinations; none of the recent CO BACT determinations for this source category utilized add-on controls for package boilers.

Solvay proposes a BACT CO emission limit of 0.037 lb CO/MMBtu (50 ppm at 3% O_2) when firing natural gas which is consistent with recent BACT determination for natural gas-fired boilers.

5.5 BACT Review – VOC Emissions

The BACT review process described in Section 5.0 is applied to potential VOC emission controls for Solvay's natural-gas fired package boiler in this subsection.

Analogous to CO emissions, the VOC emissions from boilers depend on the efficiency of natural gas combustion since VOC is emitted from natural gas-fired boilers as a result of incomplete combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased VOC emissions. VOC emissions can be reduced by operating the boiler with higher furnace temperatures, higher excess oxygen levels, turbulent mixing of fuel and combustion air, and longer furnace residence times. However, techniques for reducing VOC emissions can result in an increase in NOx emissions. Thus, as with CO, achieving low VOC and low NOx emissions is a balancing act in both boiler design and operation.

5.5.1 Identify all Available VOC Combustion Control Technologies

Table 5-7 summarizes the VOC BACT emission limits for new and modified natural gas-fired boilers in the RBLC and CA-BACT control technology databases. Emission limits range from 0.0013 to 0.024 lb/MMBtu for natural gas combustion. Many of the emission limits in these tables were expressed as pounds per hour in the original database searches, but were converted to lb/MMBtu to make the emission limits comparable.

The technologies identified in these databases include GCP and oxidation catalysts in one instance. Note that only one BACT determination entry from the RBLC database search, Calpine Turner Energy Center, indicated that oxidation catalyst add-on controls (i.e., catalytic oxidation) was considered BACT. However, the RBLC includes a note on Calpine Turner Energy Center stating, "Facility will never be built. Did not receive a site certificate from the Oregon Energy Facility Siting Council." In addition, as described in Section 5.4.2 catalytic oxidation is not considered technologically feasible for package boilers.

For the RBLC searches, the EPA database was queried for natural gas combustion (primarily RBLC codes 11.310 for > 250 MMBtu/hr and 12.310 for 100 – 250 MMBtu/hr) for the lowest VOC emission rates and the subsequent results were culled so that only boilers with ratings greater than 100 MMBtu/hr (roughly ½ the size of the Solvay boiler) and less than 500 MMBtu/hr (roughly twice the size of the Solvay boiler) were included. Searches which provided non-boiler emission sources such as duct burners at power plants were removed so that only boiler-type sources were included. Only limits used for BACT determinations, and not "case-by-case" or "other" determinations are considered for the listings in Table 5-7.

There were no CA-BACT listings for VOC controls for boilers rated between 100 MMBtu/hr and 500 MMBtu/hr.

Table 5-7. VOC Control Determinations for Natural Gas-Fired Boilers from RBLC

RBLC ID	RBLC Process Type	Facility	Permit Date	Process	Throughput (MMBtu/hr)	Controls	BACT Limit (lb/MMBtu)
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	152.0		0.0013
MI-0389	12.310	Consumers Energy	12/29/09	Boiler	220.0	GCP	0.0013
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	134.0		0.0015
NJ-0042	12.310	Roche Vitamins	02/05/99	Boiler	118.0		0.0017
AR-0026	12.310	Pine Bluff Energy LLC-Pine Bluff Energy Center	05/05/99	Boiler	362.0	GCP	0.0020
TX-0416	11.310	Shell Oil Company	11/24/99	Boiler	357.0	GCP	0.0027
TX-0499	12.310	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175.0		0.0040
AR-0057	12.310	Tenaska Arkansas Partners, LP	10/09/01	Boiler (2)	122.0	GCP	0.0040
AL-0160	11.310	Mobile Energy LLC	06/07/00	Boiler	378.0	GCP	0.0040
OH-0269	11.310	Biomass Energy	01/05/04	Auxiliary Boiler	247.0		0.0040
OH-0307	11.310	Biomass Energy	04/04/06	Auxiliary Boiler	247.0		0.0040
TX-0293	11.310	Gregory Power Partners LP	06/16/99	2 Auxiliary Boilers	405.0	Natural Gas	0.0042
OR-0046	12.310	Calpine Turner Energy Center, LLC	01/06/05	Auxiliary Boiler	139.3	OC	0.0044
MN-0066	12.310	Northern States Power Co. - Riverside Plant	05/16/06	Auxiliary Boiler	160.0	GCP	0.0050
AL-0128	12.310	Alabama Power Co. - Theodore Cogeneration	03/16/99	Boiler	220.0	GCP	0.0050
SC-0061	11.310	Columbia Energy LLC	04/09/01	2 Boilers	350.0	GCP	0.0050
SC-0071	11.310	Columbia Energy LLC	04/09/01	2 Auxiliary Boilers	350.0	GCP	0.0050
LA-0254	11.310	Entergy Louisiana LLC	08/16/11	Auxiliary Boiler	338.0	GCP	0.0054
NC-0101	12.310	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.2	GCP	0.0054
WI-0228	12.310	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230.0	GCP	0.0054
WV-0023	12.310	Longview Power, LLC	03/02/04	Auxiliary Boiler	225.0	GCP	0.0054
IN-0085	12.310	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125.0	GCP	0.0054
CO-0041	11.310	American Soda LLP, Pineance Facility	05/06/99	2 Boilers	258.7	GCP	0.0054
IA-0088	11.310	Archer Daniels Midland	06/29/07	2 Boilers	292.5	GCP	0.0054
OH-0310	12.310	American Municipal Power Generating Station	02/07/08	Auxiliary Boiler	150.0		0.0055
IA-0067	11.310	Midamerican Energy Company	06/17/03	Auxiliary Boiler	429.4	GCP	0.0055
TX-0414	12.310	Fina Oil & Chemical Company	04/22/99	Boiler	227.0	GCP	0.0070
AL-0199	11.310	Weyerhaeuser Company	11/15/02	Boiler	300.0		0.0100
VA-0278	12.310	Virginia Commonwealth University East Plant	03/31/03	Boiler (3)	151.0	GCP	0.0139
VA-0278	12.310	Virginia Commonwealth University	03/31/03	3 Boilers	150.8	GCP	0.0139
VA-0270	12.310	Virginia Commonwealth University	03/31/03	Boiler	150.0	GCP	0.0140
TX-0511	11.310	BASF Fina Petrochemicals	02/03/06	2 Boilers	425.4		0.0141
TX-0419	11.310	Calpine Construction Finance Co., LP	03/22/00	3 Auxiliary Boilers	380.0	GCP	0.0200
TN-0089	12.310	Proctor & Gamble Manufacturing Company	03/05/01	Utility Boiler	225.0		0.0240

GCP = Good Combustion Practices, OC = Oxidation Catalyst

The same potential control technologies which are used to control CO as described in Section 5.4.1 (combustion controls, flares, afterburning, thermal oxidation, and catalytic oxidation) are also applicable to VOC. The detailed descriptions of these control technologies are provided in Section 5.4.1 and are not repeated here.

5.5.2 Eliminate Technologically Infeasible Technologies

Based on the RBLC and CA-BACT database searches and BACT determinations for similar boilers, only combustions controls (GCP) are considered technically feasible controls for VOCs – same conclusions as for CO. Oxidation Catalysts are not considered technically viable control options for package boilers for both CO and VOC.

For similar BACT determinations of auxiliary package boilers, catalytic oxidation has been considered technically infeasible.[31] Industrial package boilers are pre-assembled units that are delivered to the site as a prefabricated unit. Due to shipping size constraints, package boilers are very compact. The small furnace volumes of package boilers preclude application of a number of control alternatives that may be applied to field-erected boilers, which typically are constructed with large furnace volumes.

The oxidation catalyst must be placed within a section of the furnace where the flue gas temperature is consistently 600 °F to 800 °F in the presence of a catalyst.[32] Further, the catalyst bed requires a large surface area (as in the full-height heat recovery steam generator of a combined cycle turbine) to limit velocity of the flue gases across the catalyst bed and to limit adverse pressure drop. The application of oxidation catalyst technology within the compact design of a package boiler is concluded to be not technically feasible.

The VOC concentrations for the proposed natural gas-fired package boiler at Solvay are expected to be low and recent BACT determinations for similar package boilers concluded that all add-on controls for VOC were technically infeasible because the boiler's VOC emission levels were at or below the exhaust concentrations that can be theoretically achieved with any add-on controls.

Table 5-8 summarizes the feasibility of potential VOC controls for natural gas-fired package boilers. Only GCP is considered BACT for VOC.

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[31] Duke Energy, Cliffside Steam Station, North Carolina: http://daq.state.nc.us/permits/psd/docs/cliffside/Top-down_BACT_for_Auxiliary_Boiler_%209-19-06.pdf

[32] EPA, document no. EPA-452/F-03-018: *Air Pollution Control Technology Fact Sheet – Catalytic Incinerator*, p. 3. http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

Table 5-8. Candidate VOC Controls

Control Technology	Commercially Available	Technically Feasible?
Combustion Controls	Available	Feasible
Flares	Not demonstrated for natural gas-fired boiler VOC controls	Infeasible
Afterburning	Not demonstrated for natural gas-fired boiler VOC controls	Infeasible
Thermal Oxidation	Not demonstrated for natural gas-fired boiler VOC controls	Infeasible
Catalytic Oxidation	Not demonstrated for natural gas-fired package boiler VOC controls	Infeasible

5.5.3 Rank the Remaining Technologies by Control Effectiveness

The only remaining technically feasible VOC control technology is GCP.

5.5.4 Evaluate the Most Effective Control Based on a Case-by-Case Consideration of Energy, Environmental, and Economic Impact; Then Select the VOC BACT

GCP are selected as BACT for VOC control for Solvay's natural-gas fired boiler and these conclusions are consistent with recent BACT determinations; none of the recent VOC BACT determinations for this source category utilized add-on controls for VOC.

Solvay proposes a BACT VOC emission limit of 0.0054 lb VOC/MMBtu (based on AP-42 emission factors) when firing natural gas which is consistent with recent BACT determination for natural gas-fired boilers.

6.0 GHG BACT ANALYSIS REPORT

As described above, the addition of the package boiler at the Solvay facility will trigger a PSD-level modification to Solvay's air permit, and as one component of that permitting application, the GHG emissions and associated BACT are addressed.

Since Wyoming has not accepted authority for administering the federal PSD rules related to GHGs (40 CFR 52.21), the GHG part of this permit application is to be processed by the United States Environmental Protection Agency (EPA), not Wyoming. The GHG BACT analysis was prepared in a separate document and a copy of the GHG BACT report submitted to EPA is provided in Appendix H: .

7.0 AIR QUALITY IMPACT EVALUATION – CLASS II AREAS

The PSD requirements provide for a system of area classifications which affords States an opportunity to identify local land use goals. Each classification differs in terms of the amount of growth it will permit before significant air quality deterioration would be deemed to occur. There are three area classifications:

- A Class I Area designation involves those areas where almost no change from current air quality is allowed. These areas include wilderness and nationally protected pristine areas.
- A Class II Area designation indicates areas where moderated change is allowed and can accommodate normal well-managed industrial growth, but where air quality constraints are nevertheless desired.
- A Class III Area designation indicates areas where substantial industrial or other growth is allowed and where increases in concentrations up to the national standards would be insignificant. There are no Class III areas in the United States.

The Class I and II areas are subject to different limitations on the allowable increases in ambient concentrations (called increments). Many Class I areas also included additional analyses, and thus employ different numerical approaches not normally considered for the Class II Area. Thus, Class I and Class II impacts are considered separately. This section describes the Class II Area impact analysis. The Class I Area impact analysis is described in Section 8.0.

This section summarizes the applicable ambient air quality standards (Section 7.1), the modeling methodologies used to determine potential air quality impacts (Sections 7.2 through 7.6), and the results of the impact analyses from Solvay's proposed boiler project (Section 7.7) at Class II areas around the Solvay facility. As summarized in Section 7.7, the maximum modeled impacts from the facility show that Solvay will comply with the National Ambient Air Quality Standards (NAAQS)/WAAQS and PSD increments at all Class II areas. The methodology for this impact analyses is based on Solvay's impact modeling protocols (initial version dated July 9, 2012; revised version dated October 22, 2012).

The proposed gas-boiler and associated production debottleneck results in a significant net emissions increase in PM_{10}, $PM_{2.5}$, CO, and NO_X, and VOC emissions, as described in Section 3.0 of this report. As required by the Wyoming permitting rules, the impacts of these pollutants must be estimated for the areas surrounding the facility, which are Class II areas. PM_{10}, $PM_{2.5}$, CO, and NO_X impacts are estimated using the AERMOD (AMS [American Meteorological Society]/EPA [Environmental Protection Agency] Regulatory Model) dispersion model and three years (2009 to 2011) of meteorological data measured onsite at the Solvay facility. Emissions of SO_2, lead, and fluorides did not exceed their respective SERs and thus are insignificant and were not evaluated in the impact analyses.

7.1 Ambient Air Quality Standards

Table 7-1 shows the applicable Wyoming Class II standards, PSD increments, and significant impact level (SIL) for each modeled pollutant. For PM_{10}, $PM_{2.5}$, CO, and NO_X, an air quality dispersion analysis was conducted to demonstrate compliance with the applicable standard and increment. Unlike the other pollutants, VOCs do not have an applicable standard but are evaluated as ozone precursors. Thus, a separate analysis for VOC emissions and related ozone impacts is discussed in Section 10.0.

Table 7-1. Applicable Class II Ambient Air Quality Standards, Increments, and Significant Impact Levels

Criteria Pollutant	Averaging Time	Ambient Standard μg/m³ (ppm)	Class II PSD Increment (μg/m³) [a]	Class II SIL (μg/m³)
PM_{10}	24-hour	150 [a]	30	5
	Annual	50	17	1
$PM_{2.5}$	24-hour	35[b]	9	1.2
	Annual	15	4	0.3
O_3	8-hour	149 (0.075) [c]	NA	NA
CO	1-hour	40,000 (35) [a]	NA	2,000
	8-hour	10,000 (9) [a]		500
NO_2	1-hour	189 (0.100) [d]	NA	7.5
	Annual	100 (0.053)	25	1

[a] Not to exceed more than once per year.
[b] 98th percentile 24-hour average concentration.
[c] Three-year average of the annual fourth-highest daily maximum 8-hr concentration.
[d] 98th percentile of the maximum daily 1-hour average values, averaged over 3 years.

7.2 General Modeling Approach

The PSD modeling analysis involves two phases: a preliminary analysis (referred to as a significant impact analysis) and, if necessary, a full impact analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements.

The results of the preliminary analysis determine whether a full impact analysis (facility plus competing regional sources) for a particular pollutant is necessary. If the ambient impacts from the preliminary analysis are greater than the significant impact level (see Table 7-1), then the extent of the significant impact area (SIA) of the proposed project is to be determined and full modeling for the NAAQS and PSD increments is performed as necessary.

The emissions, source characterizations, and modeling methodologies utilized for these analyses are provided in Sections 7.3 through 7.6.

7.3 Emission Characterization for Modeling

Table 7-2 shows all the Solvay sources (modeled or not), whether existing or new and contemporaneous or debottlenecked, which runs they were included in Significant Impact Area (SIA), or full/competing source runs, and, if not included in any modeling run, the reason for the exclusion.

Per July 16, 2012 WDEQ comments on the July 9, 2012 modeling protocol, Solvay excluded emergency equipment from the 1-hour NO_2 impact analyses, but included these emergency sources, where appropriate, when modeling other pollutants and averaging periods. Throughout the impact analysis, Solvay has assumed that the emergency sources operate no more than 500 hours per year and 4 hours per day during normal facility operations (e.g., no power outage).

In addition, all permitted sources at the facility were characterized and included in the impact analyses per WDEQ's request. Also, note that per Solvay's October 5, 2012, communications with WDEQ, fugitive sources of particulate emissions (both $PM_{2.5}$ and PM_{10}) for near-field short-term modeling (24-hour average) were excluded from all significant impact level, increment, and NAAQS/WAAQS modeling analyses per WDEQ policy.

WDEQ Source ID	Source Description	Annual Operation (hr/yr)	Type*	In SIA?	In Full?	Exclude Reason***
--- (109)	Package Boiler	8,760	New	Yes	Yes	
2A	Ore Crusher Building #1	8,760	DE	Yes	Yes	
6A	Product Silo - Top #1	8,760	DE	Yes	Yes	
6B	Product Silo - Bottom #1	8,760	DE	Yes	Yes	
7	Product Loadout Station	8,760	DE	Yes	Yes	
10	Coal Crushing & Storage	8,760	E	No	Yes	
11	Coal Transfer Station	8,760	E	No	Yes	
14	Boiler Coal Bunker	8,760	E	No	Yes	
15	DR-1 & 2 Steam Tube Dryers	8,760	DE	Yes	Yes	
16	Dryer Area	8,760	DE	Yes	Yes	
17	"A" & "B" Calciners	8,760	DE	Yes	Yes	
18	#1 Coal-Fired Boiler	8,760	E	No	Yes	
19	#2 Coal-Fired Boiler	8,760	E	No	Yes	
24	Boiler Ash Silo	8,760	E	No	Yes	
25	Alkaten Crushing	8,760	E	No	Yes	
26	DR-3 Alkaten Product Dryer	8,760	E	No	Yes	
27	Alkaten Product Bagging & Loadout	8,760	E	No	Yes	
30	Lime Bin #1	8,760	E	No	Yes	
31	Lime Bin #2	8,760	E	No	Yes	
33	Sulfur Burner	8,760	CE	Yes	Yes	
35	Sulfite Dryer	8,760	CE	Yes	Yes	
36	Sulfite Product Bin #1	8,760	CE	Yes	Yes	
37	Sulfite Product Bin #2	8,760	CE	Yes	Yes	
38	Sulfite Product Bin #3	8,760	CE	Yes	Yes	
44	Lime Unloading	4,380	E	No	Yes	
46	Ore Transfer Station	8,760	DE	Yes	Yes	
48	"C" Calciner	8,760	DE	Yes	Yes	
50	"C" Train Dryer Area	8,760	DE	Yes	Yes	
51	Product Dryer #5	8,760	DE	Yes	Yes	
52	Product Silo - Top #2	8,760	DE	Yes	Yes	
53	Product Silo - Bottom #2	8,760	DE	Yes	Yes	
54	T-200 Storage Bin	8,760	E	No	Yes	
62	Carbon Bin	8,760	E	No	Yes	
63	Perlite Bin	8,760	E	No	Yes	
66	Carbon/Perlite	8,760	E	No	Yes	
67	Bottom Ash	8,760	E	No	Yes	

WDEQ Source ID	Source Description	Annual Operation (hr/yr)	Type*	In SIA?	In Full?	Exclude Reason***
68	Trona Products Bagging Silo	8,760	E	No	Yes	
70	Sodium Sulfite Bagging Silo	8,760	CE	Yes	Yes	
71	Metabisulfite Bagging Silo	8,760	E	No	Yes	
73	Metabisulfite Dryer	8,760	E	No	Yes	
76	"D" Train Primary Ore Screening	8,760	DE	Yes	Yes	
79	Ore Transfer Point	8,760	DE	Yes	Yes	
80	"D" Ore Calciner	8,760	DE	Yes	Yes	
81	"D" Train Dryer Area	8,760	DE	Yes	Yes	
82	DR-6 Product Dryer	8,760	DE	Yes	Yes	
88	Trona Products Transloading #2	8,760	E	No	Yes	
88b	Trona Products Transloading #3	8,760	CN	Yes	Yes	
92	Trona Products Bin #2	8,760	E	No	Yes	
93	Trona Products Rail Loadout	8,760	E	No	Yes	
94	Sulfite Loadout	8,760	CE	Yes	Yes	
95	Trona Products Loadout Bin	8,760	E	No	Yes	
96	T-200 TPX Bin #1	8,760	E	No	Yes	
97	Soda Ash TPX	8,760	E	No	Yes	
98	TPX Area	8,760	E	No	Yes	
99	Crusher Baghouse #2	8,760	DE	Yes	Yes	
100	Calciner Coal Bunker	8,760	DE	Yes	Yes	
101	Trona Products Dryer DR-7	8,760	E	No	Yes	
102	Trona Products Loadout and Silo	8,760	E	No	Yes	
103	East Ore Reclaim	8,760	DE	Yes	Yes	
104	West Ore Reclaim	8,760	DE	Yes	Yes	
105	S-300 Dryer #1	8,760	CN	Yes	Yes	
106	S-300 Silo and Rail Loadout #1	8,760	CN	Yes	Yes	
107	S-300 Dryer #2	8,760	CN	Yes	Yes	
108	S-300 Silo and Rail Loadout #2	8,760	CN	Yes	Yes	
E3	Waukesha F18GSI (GVBH Compressor)	8,760	CN	Yes	Yes	
E4	GM 8.1L (GVBH Pump)	8,760	CN	Yes	Yes	
E5	GM 4.3L (GVBH Pump)	8,760	CN	Yes	Yes	
MV	Mine Vent	8,760	E	No	Yes	
GVBH Fl	GVB Flare (Gas Incinerator)	8,760	CN	Yes	Yes	
901	Cooling Tower - High Flow	8,760	E	No	Yes	
902	Cooling Tower - Low Flow	8,760	E	No	Yes	
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	500	CN	Yes	Yes**	EMG

WDEQ Source ID	Source Description	Annual Operation (hr/yr)	Type*	In SIA?	In Full?	Exclude Reason***
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	CN	Yes	Yes**	EMG
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	CN	Yes	Yes**	EMG
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	CN	Yes	Yes**	EMG
GND	Generator Engine – C/S Plant	500	E	No	Yes**	EMG
GNS-1	Steam Plant Generator Engine #1	500	E	No	Yes**	EMG
GNS-2	Steam Plant Generator Engine #2	500	E	No	Yes**	EMG
FRP	Emergency Fire Pump Engine	500	E	No	Yes**	EMG
PB	Emergency Pony Boiler	500	E	No	Yes**	EMG
None	DECA Melt Tank/Stamler System	8,760	CN	No	No	NS
None	DECA Stockpile/Handling	8,760	CN	Yes	Yes	
None	DECA Haul Road Activity	8,760	CN	Yes	Yes	
---	Coal Road Activity	8,760	E	No	Yes	
---	Rail Switching Engines	4,992	E	No	Yes	
---	Katolight SENL80FGC4 NG-fired Generator	8,760	CN	Yes	Yes	
---	TEG Dehydration Unit	8,760	CN	No	No	NS
---	Two (2) Reboiler Heaters	8,760	CN	Yes	Yes	

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.
** Excluded for 1-hour NO_2 as seldom utilized source. Assumed to operate no more than 4 hours per day and 500 hours per year during normal facility operations.
*** Exclusion reason: EMG = seldom-used emergency unit, NS = not a source of criteria pollutant emissions.

7.3.1 Emissions for the Significant Impact Area Analysis

The PSD modeling analysis involves two phases: a preliminary analysis (referred to as a significant impact analysis) and, if necessary, a full impact analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements.

The results of the preliminary analysis determine whether a full impact analysis (facility plus competing regional sources) for a particular pollutant is necessary. If the ambient impacts from the preliminary analysis are greater than the significant impact level (see Table 7-1), then the extent of the significant impact area (SIA) of the proposed project is to be determined.

Solvay has further discussed the SIA approach with WDEQ to attempt to make use of the post-project vs. pre-project changes in short-term emissions where appropriate in the short-term modeling analyses.[33] Solvay's proposed approach as approved by WDEQ for all short-term averaging periods in the significant impact analyses (i.e., 1-hour NO_2, 24-hour PM, short-term CO, etc.) is as follows: For each existing source, the modeled net emissions increase was the potential-to-emit emissions rate (lb/hr; post-project) minus the maximum actual short-term emissions rate (lb/hr; pre-project). The maximum actual short-term emissions rate was selected as the highest actual short-term emissions rate that occurred during any time over a two-year period when this data was available. Note that for some sources (mostly combustion sources), Solvay analyzed its production data and determined that production rates were much lower than permitted allowable production rates. In these instances, Solvay chose to utilize average short-term emission rates to define pre-project short-term emissions, rather than utilizing a maximum short-term emission rate. This average emission data was derived from Solvay's annual emissions reports which are provided to WDEQ.

The regulations for the PSD applicability calculations (to determine if modification is major or minor) allow for the selection of any two-year period over any previous ten years for emissions netting purposes. For Solvay, PSD applicability for PM was determined using 2009 and 2010 data. For NO_X and CO, 2007 and 2008 data were utilized. Solvay determined the maximum actual emissions for modeling with the same years utilized to determine the baseline actual emissions for the PSD applicability calculations.

For the annual average impact analyses, to determine the long-term SIA emissions for modeling, the actual annual emissions (two-year average) were subtracted from the annual average PTE.

If the maximum impact (or the three-year average maximum impact for the probabilistic standards; 1-hour NO_2 and 24-hour and annual $PM_{2.5}$) using these emissions was less than the applicable SIL, then the analysis was assumed complete for that pollutant and averaging time. If the pollutant impact exceeded the SIL, a full impact analysis was conducted, which included impacts from nearby sources as discussed further in Section 7.6.

[33] E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay PSD: Modeling Information (fugitive PM and ambient boundary), October 8, 2012.

A summary of the SIA emission rates utilized in the SIL analysis is provided in Table 7-3. Table 7-4 through 7-8, provide the details of the emissions calculations use to determine the SIA emissions utilized in the SIA modeling analyses. Note that with the exception of the fugitive sources (areas and volumes), PM_{10} emissions were conservatively utilized to define the $PM_{2.5}$ SIA for all other Solvay sources.

Table 7-3. SIA Emissions Summary

		SIA Emissions; PTE - Max. Actual (lb/hr) for Short-term (ST), PTE – Annual Actual (lb/hr) for Long-term (LT)				
Source	Description	ST PM_{10}	LT PM_{10}	ST NO_X	LT NO_X	ST CO
109	Package Boiler	1.89	1.89	2.79	2.79	9.4
2A	Ore Crusher Building #1	---	---	---	---	---
6A	Product Silo - Top #1	---	---	---	---	---
6B	Product Silo - Bottom #1	---	0.50	---	---	---
7	Product Loadout Station	---	0.69	---	---	---
15	DR-1 & 2 Steam Tube Dryers	0.91	1.03	0	0	0
16	Dryer Area	---	0.05	---	---	---
17	"A" & "B" Calciners	15.50	15.97	50.74	54.71	966.7
33	Sulfur Burner	---	---	0.30	0.25	---
35	Sulfite Dryer	0.59	0.64	---	---	---
36	Sulfite Product Bin #1	0.10	0.07	---	---	---
37	Sulfite Product Bin #2	0.10	0.07	---	---	---
38	Sulfite Product Bin #3	0.10	0.07	---	---	---
46	Ore Transfer Station	---	---	---	---	---
48	"C" Calciner	3.03	5.65	12.60	13.83	513.8
50	"C" Train Dryer Area	---	0.04	---	---	---
51	Product Dryer #5	1.50	1.55	9.45	9.84	182.3
52	Product Silo - Top #2	---	0.02	---	---	---
53	Product Silo - Bottom #2	---	0.27	---	---	---
70	Sodium Sulfite Bagging Silo	---	0.26	---	---	---
76	"D" Train Primary Ore Screening	---	0.07	---	---	---
79	Ore Transfer Point	---	0.02	---	---	---
80	"D" Ore Calciner	1.09	2.70	7.99	9.35	418.5
81	"D" Train Dryer Area	---	0.03	---	---	---
82	DR-6 Product Dryer	0.91	1.04	14.77	16.71	300.0
88b	Trona Products Transloading #3	0.20	0.20	---	---	---
94	Sulfite Loadout	---	0.28	---	---	---
99	Crusher Baghouse #2	---	---	---	---	---
100	Calciner Coal Bunker	---	0.15	---	---	---
103	East Ore Reclaim	---	---	---	---	---
104	West Ore Reclaim	---	---	---	---	---
105	S-300 Dryer #1	---	1.25	---	---	---
106	S-300 Silo and Rail Loadout #1	---	0.10	---	---	---

Source	Description	SIA Emissions; PTE - Max. Actual (lb/hr) for Short-term (ST), PTE – Annual Actual (lb/hr) for Long-term (LT) ST PM_{10}	LT PM_{10}	ST NO_X	LT NO_X	ST CO
107	S-300 Dryer #2	1.30	1.30	---	---	---
108	S-300 Silo and Rail Loadout #2	0.10	0.10	---	---	---
E3	Waukesha F18GSI (GVBH compressor)	---	---	0.60	0.60	0.9
E4	GM 8.2L (GVBH Pump)	---	---	0.30	0.30	0.5
E5	GM 4.3L (GVBH Pump)	---	---	0.20	0.20	0.3
GVBH Fl	GVB Flare	---	---	5.90	5.90	3.4
RH	Two (2) Reboilers Heaters	---	---	0.02	0.02	0.02
KATO	Katolight SENL80FGC4 NG-Fired Generator	---	---	0.3	0.3	0.3
EG3	Caterpillar 3456 (Emergency Shaft Generator)	0.10	0.03	10.50	0.60	12.9
EG4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	0.03	0.01	4.00	0.23	3.5
EG4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	0.03	0.01	4.00	0.23	3.5
EG4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	0.03	0.01	4.00	0.23	3.5
DR	DECA Haul Road Activity	---	1.75 ($PM_{2.5}$ = 0.22)	0.96	0.96	0.83
DECA	DECA Stockpile/Handling	---	0.001 ($PM_{2.5}$ = 0.0002)	---	---	---

Table

WDEQ Source ID	Source Description	Type*	PM PTE Emissions (lb/hr)	Max. Actual Daily Operating Hours (2009/2010)	Max. Actual Daily PM Emissions, 2009/2010 (lb/hr) *****	SIA Emissions; PTE - Max. Actual (lb/hr)
109	Package Boiler ***	New	1.89	---	---	1.89
2A **	Ore Crusher Building #1	DE	1.6	24	1.6	0
6A **	Product Silo - Top #1	DE	0.3	24	0.3	0
6B **	Product Silo - Bottom #1	DE	0.51	24	0.51	0
7 **	Product Loadout Station	DE	1.2	24	1.2	0
15	DR-1 & 2 Steam Tube Dryers	DE	3	24	2.09	0.91
16 ***	Dryer Area	DE	0.9	24	0.9	0
17	"A" & "B" Calciners	DE	30	24	14.50	15.50
33	Sulfur Burner	CE	---	---	---	---
35	Sulfite Dryer	CE	1.4	24	0.81	0.59
36 ***	Sulfite Product Bin #1	CE	0.1	24	---	0.1
37 ***	Sulfite Product Bin #2	CE	0.1	24	---	0.1
38 ***	Sulfite Product Bin #3	CE	0.1	24	---	0.1
46 **	Ore Transfer Station	DE	0.71	24	0.71	0
48	"C" Calciner	DE	8	24	4.97	3.03
50 **	"C" Train Dryer Area	DE	0.7	24	0.7	0
51	Product Dryer #5	DE	2.4	24	0.90	1.50
52 **	Product Silo - Top #2	DE	0.5	24	0.5	0
53 **	Product Silo - Bottom #2	DE	0.45	24	0.45	0
70 **	Sodium Sulfite Bagging Silo	CE	0.27	24	0.27	0
76 **	"D" Train Primary Ore Screening	DE	2.45	24	2.45	0
79 **	Ore Transfer Point	DE	0.84	24	0.84	0
80	"D" Ore Calciner	DE	10	24	8.91	1.09
81 **	"D" Train Dryer Area	DE	0.5	24	0.5	0
82	DR-6 Product Dryer	DE	3.45	24	2.54	0.91
88b ***	Trona Products Transloading #3	CN	0.2	0	0	0.2
94 **	Sulfite Loadout	CE	0.3	24	0.3	0
99 **	Crusher Baghouse #2	DE	3.2	24	3.2	0
100 **	Calciner Coal Bunker	DE	0.2	24	0.2	0

Table 7-4. SIA Emissions: Short-term PM, Contd.

WDEQ Source ID	Source Description	Type*	PM PTE Emissions (lb/hr)	Max. Actual Daily Operating Hours (2009/2010)	Max. Actual Daily PM Emissions, 2009/2010 (lb/hr) *****	SIA Emissions; PTE - Max. Actual (lb/hr)
103 **	East Ore Reclaim	DE	0.33	24	0.33	0
104 **	West Ore Reclaim	DE	0.27	24	0.27	0
105 **	S-300 Dryer #1	CN	1.3	24	1.3	0
106 **	S-300 Silo and Rail Loadout #1	CN	0.1	24	0.1	0
107 ***	S-300 Dryer #2	CN	1.3	0	0	1.3
108 ***	S-300 Silo and Rail Loadout #2	CN	0.1	0	0	0.1
E3	Waukesha F18GSI (GVBH compressor)	CN	---	---	---	---
E4	GM 8.2L (GVBH Pump)	CN	---	---	---	---
E5	GM 4.3L (GVBH Pump)	CN	---	---	---	---
GVBH Fl	GVB Flare	CN	---	---	---	---
RH	Two (2) Reboilers Heaters	CN	--- ****	---	---	---
KATO	Katolight SENL80FGC4 NG-fired Generator	CN	---	---	---	---
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	CN	0.10	---	---	0.10
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
DR	DECA Haul Road Activity	CN	---	---	---	--- (fugitive)
DECA	DECA Stockpile/Handling	CN	---	---	---	--- (fugitive)

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous,
DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.

** Because particulate emissions from these sources are a function of baghouse airflow and design specifications (e.g., grain loading) and not a function of production rates, the max. daily actual emissions are equal to the daily PTE emissions (there are no changes in short-term emissions).

*** Modeled emissions for these sources are PTEs.

**** Insignificant emissions.

***** Max. actual daily emissions for the following non-baghouse sources conservatively utilize the highest average daily emissions from either 2009 or 2010 (i.e., derived from WDEQ annual reports): #15, #17, #35, #48, #51, #80, #82.
For example in 2010, source #17 operated 8,276 hours with reported PM emissions of 60.0 tpy (WDEQ annual reports). Thus, the average actual emission rate for 2010 for the source equals 14.5 lb. /hr. (60.0 tpy x 2000 lb. /ton / 8,276 hr. /yr. = 14.5 lb. /hr.).

Note: During normal facility operating conditions, emergency generators (EG3, EG4a-c) are assumed to operate no more than 4 hours/day; max. lb/hr emissions are adjusted by 4/24 for short-term modeling.

Table 7-5. SIA Emissions: Long-term PM

WDEQ Source ID	Source Description	Type*	Allowable Annual Operation (hr/yr)	PM PTE Emissions (tpy)	2009/2010 Average Actual Emissions (tpy)	SIA Emissions; PTE - Actual (tpy)
109	Package Boiler **	New	8,760	8.3	---	8.3
2A	Ore Crusher Building #1	DE	8,760	7.0	7.0	0
6A	Product Silo - Top #1	DE	8,760	1.3	1.3	0
6B	Product Silo - Bottom #1	DE	8,760	2.2	0.04	2.2
7	Product Loadout Station	DE	8,760	5.3	2.2	3.0
15	DR-1 & 2 Steam Tube Dryers	DE	8,760	13.1	8.6	4.5
16	Dryer Area	DE	8,760	3.9	3.7	0.2
17	"A" & "B" Calciners	DE	8,760	131.4	61.4	70.0
33	Sulfur Burner	CE	8,760	---	---	---
35	Sulfite Dryer	CE	8,760	6.1	3.3	2.8
36	Sulfite Product Bin #1	CE	8,760	0.4	0.1	0.3
37	Sulfite Product Bin #2	CE	8,760	0.4	0.1	0.3
38	Sulfite Product Bin #3	CE	8,760	0.4	0.1	0.3
46	Ore Transfer Station	DE	8,760	3.1	3.1	0
48	"C" Calciner	DE	8,760	35.0	10.3	24.8
50	"C" Train Dryer Area	DE	8,760	3.1	2.9	0.2
51	Product Dryer #5	DE	8,760	10.5	3.7	6.8
52	Product Silo - Top #2	DE	8,760	2.2	2.1	0.1
53	Product Silo - Bottom #2	DE	8,760	2.0	0.8	1.2
70	Sodium Sulfite Bagging Silo	CE	8,760	1.2	0.05	1.1
76	"D" Train Primary Ore Screening	DE	8,760	10.7	10.4	0.3
79	Ore Transfer Point	DE	8,760	3.7	3.6	0.1
80	"D" Ore Calciner	DE	8,760	43.8	32.0	11.8
81	"D" Train Dryer Area	DE	8,760	2.2	2.1	0.1
82	DR-6 Product Dryer	DE	8,760	15.1	10.6	4.5
88b **	Trona Products Transloading #3	CN	8,760	0.9	0	0.9
94	Sulfite Loadout	CE	8,760	1.3	0.1	1.2
99	Crusher Baghouse #2	DE	8,760	14.0	14.0	0
100	Calciner Coal Bunker	DE	8,760	0.9	0.2	0.7

Table 7-5. SIA Emissions: Long-term PM, Contd.

WDEQ Source ID	Source Description	Type*	Allowable Annual Operation (hr/yr)	PM PTE Emissions (tpy)	2009/2010 Average Actual Emissions (tpy)	SIA Emissions; PTE - Actual (tpy)
103	East Ore Reclaim	DE	8,760	1.4	1.4	0
104	West Ore Reclaim	DE	8,760	1.2	1.2	0
105	S-300 Dryer #1	CN	8,760	5.7	0.2	5.5
106	S-300 Silo and Rail Loadout #1	CN	8,760	0.4	0.001	0.4
107 **	S-300 Dryer #2	CN	8,760	5.7	0	5.7
108 **	S-300 Silo and Rail Loadout #2	CN	8,760	0.4	0	0.4
E3	Waukesha F18GSI (GVBH compressor)	CN	8,760	---	---	---
E4	GM 8.2L (GVBH Pump)	CN	8,760	---	---	---
E5	GM 4.3L (GVBH Pump)	CN	8,760	---	---	---
GVBH Fl	GVB Flare	CN	8,760	---	---	---
RH	Two (2) Reboilers Heaters	CN	8,760	--- ****	---	---
KATO	Katolight SENL80FGC4 NG-fired Generator	CN	8,760	---	---	---
EG-3 **	Caterpillar 3456 (Emergency Shaft Generator)	CN	500	0.2	0	0.2
EG-4a **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
EG-4b **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
EG-4c **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
DR	DECA Haul Road Activity	CN	8,760	7.7 ($PM_{2.5}$ = 1.0)	0	7.7 ($PM_{2.5}$ = 1.0)
DECA	DECA Stockpile/Handling	CN	8,760	0.004 ($PM_{2.5}$ = 0.0006)	0	0.004 ($PM_{2.5}$ = 0.0006)

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.

** Modeled emissions for these sources are PTEs.

*** Insignificant emissions.

WDEQ Source ID	Source Description	Type*	NOx PTE Emissions (lb/hr)	Max. Actual 1-hour NOx Emissions, 2007/2008 (lb/hr) ****	SIA Emissions; PTE - Max. Actual (lb/hr)
109	Package Boiler **	New	2.79	---	2.79
15	DR-1 & 2 Steam Tube Dryers	DE	---	---	0 ***
17	"A" & "B" Calciners	DE	116.0	88.6	27.4
33 **	Sulfur Burner	CE	0.3	---	0.3
48	"C" Calciner	DE	15	2.4	12.6
51	Product Dryer #5	DE	18	8.5	9.5
80	"D" Ore Calciner	DE	20	12.0	8.0
82	DR-6 Product Dryer	DE	30	15.2	14.8
E3 **	Waukesha F18GSI (GVBH compressor)	CN	0.6	---	0.6
E4 **	GM 8.2L (GVBH Pump)	CN	0.3	---	0.3
E5 **	GM 4.3L (GVBH Pump)	CN	0.2	---	0.2
GVBH Fl **	GVB Flare	CN	5.9	---	5.9
RH **	Two (2) Reboilers Heaters **	CN	0.02	---	0.02
KATO **	Katolight SENL80FGC4 NG-fired Generator **	CN	0.3	---	0.3
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	CN	10.5	---	0 *****
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	4.0	---	0 *****
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	4.0	---	0 *****
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	4.0	---	0 *****
DR **	DECA Haul Road Activity	CN	1.0	---	1.0

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.

** Modeled emissions for these sources are PTEs.

*** Source #15 fed by heat from boilers only, old preheaters on Source #15 are no longer used so there are no actual gaseous emissions. Solvay no longer wishes to use the Source #15 preheaters and wishes to eliminate them from the facility's air permit also; this will result in the elimination of the currently permitted nitrogen oxides (NOX) limit of 1.8 lb/hr for #15.
Thus, there is no net emissions increase from the source.

**** Max. actual hourly emissions for the following combustion sources conservatively utilize the highest average hourly emissions from either 2007 or 2008 (i.e., derived from WDEQ annual reports): #48, #51, #80, and #82. For example in 2008, source #82 operated 8,400 hours with reported NOx emissions of 64.0 tpy (WDEQ annual reports). Thus, the average actual emission rate for 2008 for the source equals 15.2 lb/hr (64.0 tpy x 2000 lb/ton / 8,400 hr/yr = 15.2 lb/hr).
Emissions for #17 are the highest 30-day rolling average lb/hr emissions from NOx CEMS data for either 2007 or 2008.

***** Emergency sources not modeled for 1-hour NO_2 per WDEQ policy.

Table 7-7. SIA Emissions: Annual NO_x

WDEQ Source ID	Source Description	Type*	Allowable Annual Operation (hr/yr)	NOx PTE Emissions (tpy)	2007/2008 Average Actual Emissions (tpy)	SIA Emissions; PTE - Actual (tpy)
109	Package Boiler **	New	8,760	12.2	---	12.2
15 **	DR-1 & 2 Steam Tube Dryers	DE	8,760	---	---	0 ***
17	"A" & "B" Calciners	DE	8,760	508.1	268.5	239.6
33 **	Sulfur Burner	CE	8,760	1.3	0.2	1.1
48	"C" Calciner	DE	8,760	65.7	5.1	60.6
51	Product Dryer #5	DE	8,760	78.8	35.7	43.1
80	"D" Ore Calciner	DE	8,760	87.6	46.6	41.0
82	DR-6 Product Dryer	DE	8,760	131.4	58.2	73.2
E3 **	Waukesha F18GSI (GVBH compressor)	CN	8,760	2.6	0	2.6
E4 **	GM 8.2L (GVBH Pump)	CN	8,760	1.3	0	1.3
E5 **	GM 4.3L (GVBH Pump)	CN	8,760	0.9	0	0.9
GVBH Fl **	GVB Flare	CN	8,760	25.8	0	25.8
RH **	Two (2) Reboilers Heaters **	CN	8,760	0.1	0	0.1
KATO **	Katolight SENL80FGC4 NG-fired Generator **	CN	8,760	1.3	0	1.3
EG-3 **	Caterpillar 3456 (Emergency Shaft Generator)	CN	500	2.6	0	2.6
EG-4a **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	1.0	0	1.0
EG-4b **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	1.0	0	1.0
EG-4c **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	1.0	0	1.0
DR **	DECA Haul Road Activity	CN	8,760	4.2	0	4.2

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.

** Modeled emissions for these sources are PTEs.

*** Source #15 fed by heat from boilers only, old preheaters on Source #15 are no longer used so there are no actual gaseous emissions. Solvay no longer wishes to use the Source #15 preheaters and wishes to eliminate them from the facility's air permit also; this will result in the elimination of the currently permitted nitrogen oxides (NO_X) limit of 1.8 lb/hr (7.9 tpy) for #15.
Thus, there is no net emissions increase from the source.

Table 7-8. SIA Emissions: Short-term CO

WDEQ Source ID	Source Description	Type*	CO PTE Emissions (lb/hr)	Max. Actual Short-term CO Emissions, 2007/2008 (lb/hr) ****	SIA Emissions; PTE - Max. Actual (lb/hr)
109	Package Boiler **	New	9.4	---	9.4
15	DR-1 & 2 Steam Tube Dryers	DE	---	---	0 ***
17	"A" & "B" Calciners	DE	1263.2	296.5	966.7
33	Sulfur Burner	CE	---	---	---
48	"C" Calciner	DE	762	248.2	513.8
51	Product Dryer #5	DE	225	42.7	182.3
80	"D" Ore Calciner	DE	1048	629.5	418.5
82 **	DR-6 Product Dryer	DE	300	---	300.0
E3 **	Waukesha F18GSI (GVBH compressor)	CN	0.9	---	0.9
E4 **	GM 8.2L (GVBH Pump)	CN	0.5	---	0.5
E5 **	GM 4.3L (GVBH Pump)	CN	0.3	---	0.3
GVBH Fl **	GVB Flare	CN	3.4	---	3.4
RH **	Two (2) Reboilers Heaters **	CN	0.02	---	0.02
KATO **	Katolight SENL80FGC4 NG-fired Generator **	CN	0.3	---	0.3
EG-3 **	Caterpillar 3456 (Emergency Shaft Generator)	CN	12.9	---	12.9
EG-4a **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	3.5	---	3.5
EG-4b **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	3.5	---	3.5
EG-4c **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	3.5	---	3.5
DR **	DECA Haul Road Activity	CN	0.83	---	0.83

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.

** Modeled emissions for these sources are PTEs.

*** Source #15 fed by heat from boilers only, old preheaters on Source #15 are no longer used so there are no actual gaseous emissions. Solvay no longer wishes to use the Source #15 preheaters and wishes to eliminate them from the facility's air permit.

**** Max. actual hourly emissions for the following combustion sources conservatively utilize the highest average hourly emissions from either 2007 or 2008 (i.e., derived from WDEQ annual reports): #17, #48, #51, and #82. For example in 2008, source #17 operated 8,344 hours with reported CO emissions of 1237.0 tpy (WDEQ annual reports). Thus, the average actual emission rate for 2008 for the source equals 296.5 lb/hr (1237.0 tpy x 2000 lb/ton / 8,344 hr/yr = 296.5 lb/hr).

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For the NAAQS analyses, the model was run with sources operating at PTE emission rates. For the PSD increment analyses, the model was run with the PSD-consuming sources (facility and competing) to demonstrate compliance with the PSD increments. As a conservative assumption, all sources at the Solvay facility were assumed to consume increment for PM_{10} (24-hour and annual) and NO_2 (annual). Section 7.3.3 describes the $PM_{2.5}$ increment inventory which considers the net changes in emissions since the major source baseline date for $PM_{2.5}$.

Table 7-9 shows gaseous (CO, and NO_X) PTE emission rates used in the full gaseous NAAQS (CO and NO_2) and increment analyses (NO_2). The NO_2/NO_x ratios listed in Table 7-9 are based on stack testing data for the larger combustion sources at the facility (#17, #18, #19, #51, #82), the ratios calculated by the MOVES mobile source model for the DECA Haul Road Activity, Coal Road Activity, and Rail Switching Engines (as provided in the modeling protocol), and the EPA's conservative default value of 0.5 for other NO_x emitting sources. The NO_2/NO_x ratios are discussed in more detail in Section 7.5.5.1.

Table 7-10 the shows the particulate PTE emission rates used in the full particulate NAAQS analyses ($PM_{2.5}$ and PM_{10}) and increment analyses (PM_{10}).

Table 7-11 provides more details regarding the particulate PTE emission rates utilized in the modeling analysis for emergency and fugitive sources.

Table 7-9. Modeled Emission Rates – Solvay Facility; Gaseous PTE Emissions

Source ID	Source Description	PTE Emissions CO (lb/hr)	PTE Emissions NO_X (lb/hr)	NO_2/NO_X Ratio
109	Package Boiler	9.4	2.8	0.5
17	"A" & "B" Calciners	1263.2	116.0	0.054
18	#1 Coal-Fired Boiler	17.5	245.0	0.069
19	#2 Coal-Fired Boiler	17.5	245.0	0.057
26	DR-3 Alkaten Product Dryer	0.07	0.25	0.5
33	Sulfur Burner	---	0.30	0.5
48	"C" Calciner	762	15.0	0.5
51	Product Dryer #5	225	18.0	0.008
73	Metabisulfite Dryer	---	0.3	0.5
80	"D" Ore Calciner	1048	20.0	0.5
82	DR-6 Product Dryer	300	30.0	0.008
101	Trona Products Dryer DR-7	0.2	0.5	0.5
108	S-300 Silo and Rail Loadout #2	---	---	---
E3	Waukesha F18GSI (GVBH Compressor)	0.9	0.6	0.5
E4	GM 8.1L (GVBH Pump)	0.5	0.3	0.5
E5	GM 4.3L (GVBH Pump)	0.3	0.2	0.5
GVBH Fl	GVB Flare (Gas Incinerator)	3.4	5.9	0.5
RH	Two (2) Reboiler Heaters	0.02	0.02	0.5
KATO	Katolight SENL80FGC4 NG-Fired Generator	0.3	0.3	0.5
MV	Mine Vent	7.8	---	---
EG3 *	Caterpillar 3456 (Emergency Shaft Generator)	12.9	10.5 (ST), 0.60 (LT)	0.5
EG4a *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	3.5	4.0 (ST), 0.23 (LT)	0.5
EG4b *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	3.5	4.0 (ST), 0.23 (LT)	0.5
EG4c *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	3.5	4.0 (ST), 0.23 (LT)	0.5
GND *	Generator Engine – C/S Plant	1.1	4.9 (ST), 0.28 (LT)	0.5
GNS1 *	Steam Plant Generator Engine #1	20.0	75.3 (ST), 4.30 (LT)	0.5
GNS2 *	Steam Plant Generator Engine #2	20.0	75.3 (ST), 4.30 (LT)	0.5
FRP *	Emergency Fire Pump Engine	1.9	9.0 (ST), 0.51 (LT)	0.5
PB *	Emergency Pony Boiler	1.0	8.1 (ST), 0.46 (LT)	0.5
Volume Sources				
DR	DECA Haul Road Activity	0.83	0.96	0.11
CR	Coal Road Activity	0.032	0.09	0.11
RAIL	Rail Switching Engines **	0.0045 lb/hr/vol.	0.031 lb/hr/vol. (ST), 0.018 lb/hr/vol. (LT)	0.11

* Emergency sources exempt from 1-hour NO_2 modeling (ST) per WDEQ policy.

** Only the portions of track which are located within each SIA or the significant concentration gradient for 1-hour NO_2 modeling (not the entire ~16 km track length) are considered for the full modeling analyses. These emissions are provided as lb/hr/volume which is a constant for each pollutant.

Table 7-10. Modeled Emission Rates – Solvay Facility; Particulate PTE Emissions

Source ID	Source Description	Type	PM_{10} PTE Emissions (lb/hr)	$PM_{2.5}/PM_{10}$ Ratio	$PM_{2.5}$ PTE Emissions (lb/hr)
109	Package Boiler	Combustion	1.89	1	1.89
2A	Ore Crusher Building #1	Baghouse	1.6	0.6	0.96
6A	Product Silo - Top #1	Baghouse	0.3	0.6	0.18
6B	Product Silo - Bottom #1	Baghouse	0.51	0.6	0.31
7	Product Loadout Station	Baghouse	1.2	0.6	0.72
10	Coal Crushing & Storage	Baghouse	0.3	0.6	0.18
11	Coal Transfer Station	Baghouse	0.2	0.6	0.12
14	Boiler Coal Bunker	Baghouse	0.4	0.6	0.24
15	DR-1 & 2 Steam Tube Dryers	Scrubber	3	1	3.00
16	Dryer Area	Baghouse	0.9	0.6	0.54
17	"A" & "B" Calciners	Combustion (ESP)	30	1	30.00
18	#1 Coal-Fired Boiler	Combustion (ESP)	5	1	5.00
19	#2 Coal-Fired Boiler	Combustion (ESP)	5	1	5.00
24	Boiler Ash Silo	Baghouse	0.3	0.6	0.18
25	Alkaten Crushing	Baghouse	1	0.6	0.60
26	DR-3 Alkaten Product Dryer	Baghouse	0.55	0.6	0.33
27	Alkaten Product Bagging & Loadout	Baghouse	0.5	0.6	0.30
30	Lime Bin #1	Baghouse	0.2	0.6	0.12
31	Lime Bin #2	Baghouse	0.2	0.6	0.12
33	Sulfur Burner	Scrubber	---	---	---
35	Sulfite Dryer	Scrubber	1.4	1	1.40
36	Sulfite Product Bin #1	Bin Vent	0.1	1	0.10
37	Sulfite Product Bin #2	Bin Vent	0.1	1	0.10
38	Sulfite Product Bin #3	Bin Vent	0.1	1	0.10
44	Lime Unloading	Baghouse	0.18	0.6	0.11
46	Ore Transfer Station	Baghouse	0.71	0.6	0.43
48	"C" Calciner	Combustion	8	1	8.00
50	"C" Train Dryer Area	Baghouse	0.7	0.6	0.42
51	Product Dryer #5	Combustion (ESP)	2.4	1	2.40
52	Product Silo - Top #2	Baghouse	0.5	0.6	0.30

Table 7-10. Modeled Emission Rates – Solvay Facility; Particulate PTE Emissions, Contd.

Source ID	Source Description	Type	PM_{10} PTE Emissions (lb/hr)	$PM_{2.5}/PM_{10}$ Ratio	$PM_{2.5}$ PTE Emissions (lb/hr)
53	Product Silo - Bottom #2	Baghouse	0.45	0.6	0.27
54	T-200 Storage Bin	Bin Vent	0.19	1	0.19
62	Carbon Bin	Bin Vent	0.13	1	0.13
63	Perlite Bin	Bin Vent	0.14	1	0.14
66	Carbon/Perlite	Scrubber	0.58	1	0.58
67	Bottom Ash	Baghouse	0.47	0.6	0.28
68	Trona Products Bagging Silo	Baghouse	0.36	0.6	0.22
70	Sodium Sulfite Bagging Silo	Baghouse	0.27	0.6	0.16
71	Metabisulfite Bagging Silo	Baghouse	0.27	0.6	0.16
73	Metabisulfite Dryer	Scrubber	0.9	1	0.90
76	"D" Train Primary Ore Screening	Baghouse	2.45	0.6	1.47
79	Ore Transfer Point	Baghouse	0.84	0.6	0.50
80	"D" Ore Calciner	Combustion (ESP)	10	1	10.00
81	"D" Train Dryer Area	Baghouse	0.5	0.6	0.30
82	DR-6 Product Dryer	Combustion (ESP)	3.45	1	3.45
88	Trona Products Transloading #2	Baghouse	0.2	0.6	0.12
88b	Trona Products Transloading #3	Baghouse	0.2	0.6	0.12
92	Trona Products Bin #2	Bin Vent	0.3	1	0.30
93	Trona Products Rail Loadout	Baghouse	0.17	0.6	0.10
94	Sulfite Loadout	Baghouse	0.3	0.6	0.18
95	Trona Products Loadout Bin	Bin Vent	0.1	1	0.10
96	T-200 TPX Bin #1	Baghouse	0.2	0.6	0.12
97	Soda Ash TPX	Baghouse	0.1	0.6	0.06
98	TPX Area	Baghouse	0.4	0.6	0.24
99	Crusher Baghouse #2	Baghouse	3.2	0.6	1.92
100	Calciner Coal Bunker	Baghouse	0.2	0.6	0.12
101	Trona Products Dryer DR-7	Baghouse	2	0.6	1.20
102	Trona Products Loadout and Silo	Baghouse	0.6	0.6	0.36
103	East Ore Reclaim	Baghouse	0.33	0.6	0.20
104	West Ore Reclaim	Baghouse	0.27	0.6	0.16
105	S-300 Dryer #1	Baghouse	1.3	0.6	0.78
106	S-300 Silo and Rail Loadout #1	Baghouse	0.1	0.6	0.06
107	S-300 Dryer #2	Baghouse	1.3	0.6	0.78
108	S-300 Silo and Rail Loadout #2	Baghouse	0.1	0.6	0.06

Table 7-10. Modeled Emission Rates – Solvay Facility; Particulate PTE Emissions, Contd.

Source ID	Source Description	Type	PM_{10} PTE Emissions (lb/hr)	$PM_{2.5}/PM_{10}$ Ratio	$PM_{2.5}$ PTE Emissions (lb/hr)
901	Cooling Tower - High Flow	Cooling Tower	0.46	0.15	0.07
902	Cooling Tower - Low Flow	Cooling Tower	0.29	0.04	0.01
E3	Waukesha F18GSI (GVBH Compressor)	Combustion	---	---	---
E4	GM 8.1L (GVBH Pump)	Combustion	---	---	---
E5	GM 4.3L (GVBH Pump)	Combustion	---	---	---
GVBH Fl	GVB Flare (Gas Incinerator)	Combustion	---	---	---
RH	Two (2) Reboiler Heaters	Combustion	---	---	---
KATO	Katolight SENL80FGC4 NG-Fired Generator	Combustion	---	---	---
MV	Mine Vent	Combustion	---	---	---
EG3 *	Caterpillar 3456 (Emergency Shaft Generator)	Combustion	0.6	1	0.60
EG4a *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	Combustion	0.2	1	0.20
EG4b *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	Combustion	0.2	1	0.20
EG4c *	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	Combustion	0.2	1	0.20
GND *	Generator Engine – C/S Plant	Combustion	0.35	1	0.35
GNS1 *	Steam Plant Generator Engine #1	Combustion	2.35	1	2.35
GNS2 *	Steam Plant Generator Engine #2	Combustion	2.35	1	2.35
FRP *	Emergency Fire Pump Engine	Combustion	0.63	1	0.63
PB *	Emergency Pony Boiler	Combustion	2.7	1	2.70
Volume Sources **					
DR	DECA Haul Road Activity	Fugitive, Tailpipe	1.75 (LT)	1 (tailpipe), 0.15 (fugitive)	0.22 (LT)
CR	Coal Road Activity	Fugitive, Tailpipe	1.79 (LT)	1 (tailpipe), 0.15 (fugitive)	0.18 (LT)
RAIL	Rail Switching Engines	Tailpipe	0.0006 lb/hr/vol. (LT)	1	0.0006 lb/hr/vol. (LT)
Area Sources **					
DECA	DECA Stockpile/Handling	Fugitive	0.001	0.15	0.0002

* The emergency sources are assumed to operate 4 hr/day; the short term lb/hr emission rates are adjusted by 4/24 to determine a daily lb/hr emission rate.
The short term lb/hr emission rates are adjusted by 500/8760 to determine an annualized lb/hr modeled emission rate.

** For these fugitive sources, per WDEQ policy, short-term PM emissions are not modeled.
PM emission rates provided in the table are the annualized lb/hr rates representative of long-term (LT) emissions for annual PM modeling.

Table 7-11. Modeled Emission Rates – Solvay Facility Emergency and Fugitive Sources; Particulate PTE Emissions

Source ID	Source Description	Operations (hr/day)	(hr/yr)	PM_{10} PTE Emissions Hourly (lb/hr)	Daily (lb/hr)	Annual (lb/hr)
Point Sources (Emergency Sources) *						
EG3	Caterpillar 3456 (Emergency Shaft Generator)	4	500	0.60	0.10	0.03
EG4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	4	500	0.20	0.03	0.01
EG4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	4	500	0.20	0.03	0.01
EG4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	4	500	0.20	0.03	0.01
GND	Generator Engine – C/S Plant	4	500	0.35	0.06	0.02
GNS1	Steam Plant Generator Engine #1	4	500	2.35	0.39	0.13
GNS2	Steam Plant Generator Engine #2	4	500	2.35	0.39	0.13
FRP	Emergency Fire Pump Engine	4	500	0.63	0.11	0.04
PB	Emergency Pony Boiler	4	500	2.70	0.45	0.15
Volume Sources (Fugitive) **						
DR	DECA Haul Road Activity	24	8,760	N/A	N/A	1.75 ($PM_{2.5}$ = 0.22)
CR	Coal Road Activity	24	8,760	N/A	N/A	1.79 ($PM_{2.5}$ = 0.18)
RAIL	Rail Switching Engines	24	8,760	N/A	N/A	0.0006 lb/hr/vol.
Area Sources (Fugitive) **						
DECA	DECA Stockpile/Handling	24	8,760	N/A	N/A	0.001 ($PM_{2.5}$ = 0.0002)

* For the emergency sources, the short term lb/hr emission rates are adjusted by 4/24 to determine a daily lb/hr modeled emission rate.

The short term lb/hr emission rates are adjusted by 500/8760 to determine an annualized lb/hr emission rate for modeling.

** For these fugitive sources, per WDEQ policy, short-term PM emissions are not modeled.

PM emission rates provided in the table are the annualized lb/hr rates representative of long-term (LT) emissions for annual PM modeling.

$PM_{2.5}$/PM_{10} MASS FRACTIONS

As shown in Table 7-10, for the particulate PTE emission rates, it was conservatively assumed that the $PM_{2.5}$ emission rate for each Solvay combustion source (and non-baghouse material handling sources like bin vents) was equal to the PM_{10} emission rate. For its baghouses, Solvay analyzed several sources of information to derive a conservative $PM_{2.5}$/PM_{10} mass fraction.

First, AP-42, Appendix B.2 provides generalized particulate size distribution data was used to derive generic $PM_{2.5}$/PM_{10} mass fractions. This AP-42 section also gives example calculations for determining both uncontrolled and controlled particle size-specific emission rates. For AP-42 Categories 3 (Process: Mechanically Generated, Materials: Aggregate, Unprocessed Ores) and 4 (Process: Mechanically Generated, Materials: Processed Ores and Nonmetallic Minerals), generalized AP-42 particle size distribution information assuming baghouse (fabric filter) controls was utilized and emission rates before and after controls were calculated for several particle size categories. As shown in Table 7-12 Solvay determined generic $PM_{2.5}$/PM_{10} mass fractions for baghouses ranging from 0.26 (Category 3) to 0.29 (Category 4).

Table 7-12. Generic $PM_{2.5}$/PM_{10} Mass Fractions for Baghouses

	Category 3: Particle Size (micrometers) [1]			Category 4: Particle Size (micrometers) [1]		
Uncontrolled Size Emissions	**2.5**	**6**	**10**	**2.5**	**6**	**10**
Generic Distribution (cumulative %) [2]	15%	34%	51%	30%	62%	85%
Cumulative Mass =< Particle Size Emissions (tpy); Unit Emissions (1 tpy)	0.15	0.34	0.51	0.30	0.62	0.85
	Category 3: Particle Size (micrometers)			**Category 4: Particle Size (micrometers)**		
Controlled Size Emissions	**0 - 2.5**	**2.5 - 6**	**6 - 10**	**0 - 2.5**	**2.5 - 6**	**6 - 10**
Collection Efficiency [3]	99.0%	99.5%	99.5%	99.0%	99.5%	99.5%
Mass in size range before control (tpy) [4]	0.15	0.34	0.51	0.30	0.62	0.85
Mass in size range after control (tpy)	0.0015	0.0017	0.0026	0.0030	0.0031	0.0043
Cumulative Mass (tpy)	0.0015	0.0032	0.0058	0.0030	0.0061	0.0104
Controlled $PM_{2.5}$/PM_{10} Mass Fraction [5]	0.26			0.29		

[1] Less than or equal to the particle size emissions. From AP-42, Appendix B.2, Table B.2.2 for fabric filters for categories 3 and 4.
Category 3 = Process: Mechanically Generated, Materials: Aggregate, Unprocessed Ores.
Category 4 = Process: Mechanically Generated, Materials: Processed Ores and Nonmetallic Minerals.
[2] Cumulative percent equal to or less than the size from AP-42, Appendix B.2, Table B.2.2.
[3] From AP-42, Appendix B.2, Table B.2-3 for fabric filters for categories 3 and 4.
[4] Uncontrolled size data are cumulative percent equal to or less than the size.
Control efficiency data apply only to the size range and are not cumulative.
[5] Based on cumulative mass values.

Second, Solvay performed a $PM_{2.5}$ stack test on its #76 baghouse. This test was not performed in conjunction with a concurrent PM_{10} stack test, but the test did indicate that measured $PM_{2.5}$ emissions (0.005 gr/dscf) are a small fraction (~22 percent) of the PM_{10} emission limit for the source (0.022 gr/dscf).

Third, Solvay has also reviewed stack test summary data for three baghouses in the soda ash industry which indicated an average $PM_{2.5}/PM_{10}$ mass fraction around 0.22 for all tests (0.13, 0.19, and 0.33 for baghouses #1, #2, and #3, respectively); consistent with the AP-42 generalized mass fractions and Solvay stack test for source #76. There was a single outlier in this test data which indicated a higher $PM_{2.5}/PM_{10}$ mass fraction of 0.56 for a single test for baghouse #3. However, the average $PM_{2.5}/PM_{10}$ mass fraction of the four tests for baghouse #3 was 0.33.

Thus, to be conservative, Solvay used a $PM_{2.5}/PM_{10}$ mass fraction of 0.6 for the baghouses based on the highest reported stack test ratio. This value is at least a factor of two higher than the AP-42 factors and is higher than all stack test data reviewed by Solvay.

As provided in Appendix I: , Solvay has calculated emissions estimates and characterized selected fugitive/mobile sources (DECA and coal roads, railroad) and refined cooling tower emissions at the facility for modeling purposes. These selected sources have not been previously modeled as part of Solvay's prior minor source permitting actions, but are included here as part of this major source permitting action per WDEQ request.

MOBILE SOURCES

Solvay has quantified both railroad and haul truck mobile emissions, which constitute the majority of mobile emissions at the facility, and these sources are included in the impact analysis where necessary. Mobile sources were characterized by strings of volume sources placed along their route. Following EPA guidance, the width of the volume sources (W) was set to the width of the road plus 6 meters. Sigma y was set to the volume source width divided by 2.15. The volume sources were spaced approximately two volume widths apart using the ISCST3 alternative line source representation. The release height was set to 1.7/2 times the vehicle height.

DECA and Coal Roads

For the DECA and coal roads, the unpaved dust emissions were calculated following AP-42 Chapter 13.2.2 (Unpaved Roads) and a $PM_{2.5}/PM_{10}$ mass fraction of 0.1 from AP-42 Chapter 13.2.2, Table 13.2.2-2 (Unpaved Roads) was applied to the fugitive dust portion (not tailpipe combustion portion) of the haul road PM_{10} emissions to estimate a $PM_{2.5}$ emission rate. For the DECA haul trucks' exhaust emissions, the EPA Tier III emission factors were used. For the coal road trucks, Heavy Duty Highway (type 62) exhaust emission factors from the EPA MOVES model were used. As provided in Appendix I: , the DECA haul road emissions were distributed over 99 volume sources spaced along the DECA haul route and coal road emissions were distributed over 87 volume sources spaced along the coal haul road route.

Railroad

For the railroad switcher locomotives, exhaust emissions were calculated based on Solvay's monthly fuel use and EPA's Emissions Factors for Locomotives (EPA-420-F-025, April 2009, Table 3). The total railroad emissions were based on a 15.8 kilometer total track length (532 total volume sources) spanning north from the Solvay facility to a main rail line. Because emissions from the railroad are spread over a large distance, the railroad emissions sources closer to the facility were expected to combine with other plumes from the Solvay facility to determine maximum modeled impacts. Thus, for the railroad sources, only the volume sources located within the SIA for each pollutant (or within the significant concentration gradient for 1-hour NO_2 modeling) were explicitly modeled in the full NAAQS and increment modeling runs to provide for reasonable model run times while still providing a conservative modeling estimate.

The calculations for the mobile sources are provided in detail on Pages 4 through 8 of Appendix I: .

Cooling Towers

On Pages 1 through 3 of Appendix I: , the emissions for the cooling towers (sources 901 and 902) have been updated/refined to provide a more realistic estimate of emissions rather than relying on previously utilized AP-42 methods for cooling towers which are known to greatly overstate cooling tower PM emissions. Using Solvay's measured electrical conductivity data, Solvay has estimated Total Dissolved Solids (TDS) content of its cooling tower circulation water which is used to calculate realistic estimates of particulate emissions from the cooling towers. In addition, calculations to estimate $PM_{2.5}$/PM and PM_{10}/PM mass fractions from the cooling towers are provided on Pages 2 and 3 of Appendix I: . These mass fractions are applied to the PM emissions from cooling towers to estimate both $PM_{2.5}$ and PM_{10} emissions.

7.3.3 Emissions for the $PM_{2.5}$ Increment Analysis

For the PSD increment analyses, the model was run with the PSD-consuming sources (facility and competing) to demonstrate compliance with the PSD increments. For $PM_{2.5}$, the increment-consuming sources were a subset of the PM_{10}-emitting sources listed in Table 7-10. The major source baseline date for $PM_{2.5}$ is October 20, 2010, so only changes in $PM_{2.5}$ emissions at Solvay since the major source baseline date consume increment. For the Solvay project, these sources include the gas-fired package boiler, the associated debottlenecked sources, and the creditable contemporaneous $PM_{2.5}$ changes at the facility since October 20, 2010.

As discussed with WDEQ, the post-project vs. $PM_{2.5}$ baseline conditions changes in short-term $PM_{2.5}$ emissions were utilized where possible for the $PM_{2.5}$ increment analysis.[34] Solvay's approach as approved by WDEQ for daily $PM_{2.5}$ increment impacts is as follows: For each increment consuming source, the modeled net emissions increase (i.e., increment consumption) was the potential-to-emit emissions rate (lb/hr; post-project) minus the maximum actual short-term emissions rate (lb/hr; representative of baseline conditions). The maximum actual short-term emissions rate was selected as the highest actual short-term emissions rate that occurred during any time over a two-year period. Note that for some combustion sources, Solvay analyzed its production data and determined that production rates were much lower than permitted allowable production rates. In these instances, Solvay chose to utilize average short-term emission rates based on annual data provided to WDEQ in its annual emissions reports, rather than maximum short-term emission rates.

Because particulate emissions are a function of baghouse airflow and design specifications (e.g., grain loading) and not a function of production rates, baghouse sources do not consume $PM_{2.5}$ increment on a short-term basis since there is no actual change in emissions since the $PM_{2.5}$ baseline date.

Per communications with WDEQ, Solvay utilized 2009 and 2010 for the characterization of both the short-term and annual $PM_{2.5}$ baseline conditions for the $PM_{2.5}$ increment consumption analyses. Short-term $PM_{2.5}$ baseline conditions were the highest daily emissions which occurred in either 2009 or 2010, and annual emissions which characterize the baseline conditions were the average of 2009 and 2010 annual emissions.

A listing of Solvay's $PM_{2.5}$ consuming sources considered in the impact analysis is provided in Table 7-13 and Table 7-14.

[34] E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay PSD: Modeling Information (fugitive PM and ambient boundary), October 8, 2012.

As shown in Appendix F: , there were only three previously permitted and creditable permit actions for contemporaneous sources at the Solvay facility which consume $PM_{2.5}$ increment since the $PM_{2.5}$ major source baseline date of October 20, 2010:

- MD-11835 on 06/21/2011 (sources EG-3, EG-4a, EG-4b, EG-4c),
- Waiver wv-11853 on 04/14/2011 (sources TEG Dehydration Unit, Two Reboilers Heaters), and
- Waiver-11822 on 04/29/2011 (Katolight SENL80FGC4 NG-fired Generator).

The TEG Dehydration Unit and the Katolight Generator are not sources of particulate emissions and don't consume $PM_{2.5}$ increment. The Two Reboilers Heaters are an insignificant source of particulate emissions. Thus, the contemporaneous sources which do consume $PM_{2.5}$ increment are EG-3, EG-4a, EG-4b, EG-4c.

Table 7-13. 24-Hour $PM_{2.5}$ Increment Consuming Sources at the Solvay Facility

WDEQ Source ID	Source Description	Type*	PM PTE Emissions (lb/hr)	Max. Actual Daily Operating Hours (2009/2010)	Max. Actual Daily PM Emissions, 2009/2010 (lb/hr)	PSD Increment Emissions; PTE - Max. Actual (lb/hr)
Project and Contemporaneous Sources Since Baseline Date Which Consume 24-Hour $PM_{2.5}$ Increment						
109	Package Boiler	New	1.89	---	---	1.89
15 ***	DR-1 & 2 Steam Tube Dryers	DE	3	24	2.1	0.91
17 ***	"A" and "B" Calciners	DE	30	24	14.5	15.50
48 ***	"C" Calciner	DE	8	24	5.0	3.03
51 ***	Product Dryer #5	DE	2.4	24	0.9	1.50
80 ***	"D" Ore Calciner	DE	10	24	8.9	1.09
82 ***	DR-6 Product Dryer	DE	3.45	24	2.5	0.91
EG-3 ****	Caterpillar 3456 (Emergency Shaft Generator)	CN	0.10	---	---	0.10
EG-4a ****	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
EG-4b ****	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
EG-4c ****	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	0.03	---	---	0.03
Project and Contemporaneous Sources Since Baseline Date Which Do Not Consume 24-Hour $PM_{2.5}$ Increment						
02A **	Ore Crusher Building #1	DE	1.6	24	1.6	0
06A **	Product Silos - Top #1	DE	0.3	24	0.3	0
06B **	Product Silos - Bottom #1	DE	0.51	24	0.51	0
07 **	Product Loadout Station	DE	1.2	24	1.2	0
16 **	Dryer Area	DE	0.9	24	0.9	0
46 **	Ore Transfer Station	DE	0.71	24	0.71	0
50 **	"C" Train Dryer Area	DE	0.7	24	0.7	0
52 **	Product Silo - Top #2	DE	0.5	24	0.5	0
53 **	Product Silo - Bottom #2	DE	0.45	24	0.45	0
76 **	"D" Train Primary Ore Screening	DE	2.45	24	2.45	0
79 **	Ore Transfer Point	DE	0.84	24	0.84	0
81 **	"D" Train Dryer Area	DE	0.5	24	0.5	0
99 **	Crusher Baghouse #2	DE	3.2	24	3.2	0
100 **	Calciner Coal Bunker	DE	0.2	24	0.2	0
103 **	East Ore Reclaim	DE	0.33	24	0.33	0
104 **	West Ore Reclaim	DE	0.27	24	0.27	0

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.
** Because particulate emissions from these sources are a function of baghouse airflow and design specifications (e.g., grain loading) and not a function of production rates, these sources do not consume PM2.5 increment on a short-term basis since there is no actual change in emissions since the baseline date.
*** These sources are conservatively modeled using an average daily actual emission rate (long-term) to represent a maximum actual daily emission rate.
For example in 2010, source #17 operated 8,276 hours with reported PM emissions of 60.0 tpy (WDEQ annual reports). Thus, the average actual emission rate for the source equals 14.5 lb/hr (60.0 tpy x 2000 lb/ton / 8,276 hr/yr = 14.5 lb/hr).

**** During normal facility operating conditions, emergency generators are assumed to operate no more than 4 hours/day; max. lb/hr emissions are adjusted by 4/24 for modeling.

Table 7-14. Annual $PM_{2.5}$ Increment Consuming Sources at the Solvay Facility

WDEQ Source ID	Source Description	Type*	Allowable Annual Operation (hr/yr)	PM PTE Emissions (tpy)	2009/2010 Average Actual Emissions (tpy)	PSD Increment Emissions; PTE - Baseline Actual (tpy)
Project and Contemporaneous Sources Since Baseline Date Which Consume Annual $PM_{2.5}$ Increment						
109	Package Boiler **	New	8,760	8.3	---	8.3
06B	Product Silos - Bottom #1	DE	8,760	2.2	0.04	2.2
07	Product Loadout Station	DE	8,760	5.3	2.2	3.0
15	DR-1 & 2 Steam Tube Dryers	DE	8,760	13.1	8.6	4.5
16	Dryer Area	DE	8,760	3.9	3.7	0.2
17	"A" and "B" Calciners	DE	8,760	131.4	61.4	70.0
48	"C" Calciner	DE	8,760	35.0	10.3	24.8
50	"C" Train Dryer Area	DE	8,760	3.1	2.9	0.2
51	Product Dryer #5	DE	8,760	10.5	3.7	6.8
52	Product Silo - Top #2	DE	8,760	2.2	2.1	0.1
53	Product Silo - Bottom #2	DE	8,760	2.0	0.8	1.2
76	"D" Train Primary Ore Screening	DE	8,760	10.7	10.4	0.3
79	Ore Transfer Point	DE	8,760	3.7	3.6	0.1
80	"D" Ore Calciner	DE	8,760	43.8	32.0	11.8
81	"D" Train Dryer Area	DE	8,760	2.2	2.1	0.1
82	DR-6 Product Dryer	DE	8,760	15.1	10.6	4.5
100	Calciner Coal Bunker	DE	8,760	0.9	0.2	0.7
EG-3 **	Caterpillar 3456 (Emergency Shaft Generator)	CN	500	0.2	0	0.2
EG-4a **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
EG-4b **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
EG-4c **	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	CN	500	0.1	0	0.1
Project and Contemporaneous Sources Since Baseline Date Which Do Not Consume Annual $PM_{2.5}$ Increment						
02A	Ore Crusher Building #1	DE	8,760	7.0	7.0	0
06A	Product Silos - Top #1	DE	8,760	1.3	1.3	0
46	Ore Transfer Station	DE	8,760	3.1	3.1	0
99	Crusher Baghouse #2	DE	8,760	14.0	14.0	0
103	East Ore Reclaim	DE	8,760	1.4	1.4	0
104	West Ore Reclaim	DE	8,760	1.2	1.2	0

* Type: CN = New Contemporaneous, CE = Existing Contemporaneous, DE = Debottlenecked Existing Source, E = Existing Source, New = New Project Source.
** Modeled emissions for these sources are PTEs.

7.4 Source Characterization for Modeling

The source parameters for the sources at the facility are shown in Table 7-15. A close up layout of the sources and buildings at the facility is shown in Figure 7-1. Since sources EG4a, EG4b, and EG4c have identical stack parameters and are located adjacent to each other, they were collocated for modeling purposes. Figure 7-2 shows the locations of all modeled sources with respect to the facility boundary. Corresponding source locations and source elevations above sea level utilized in the modeling analysis are provided in Table 7-16.

Table 7-15. Source Release Parameters – Solvay Facility

Source ID	Source Description	Stack Height		Exit Temperature		Exit Velocity		Exit Diameter	
		(ft)	(m)	(F)	(K)	(ft/s)	(m/s)	(ft)	(m)
109	Package Boiler	180.0	54.9	350.0	449.8	58.2	17.73	6.00	1.83
2A	Ore Crusher Building #1	23.0	7.0	67.7	293.0	52.0	15.85	3.50	1.06
6A	Product Silo - Top #1	133.0	40.5	96.5	309.0	82.0	24.99	2.10	0.64
6B	Product Silo - Bottom #1	20.5	6.2	74.9	297.0	33.0	10.06	2.20	0.67
7	Product Loadout Station	82.0	25.0	67.7	293.0	64.0	19.51	2.50	0.75
10	Coal Crushing & Storage	13.3	4.1	67.7	293.0	18.0	5.49	2.00	0.60
11	Coal Transfer Station	35.3	10.8	67.7	293.0	21.0	6.40	1.80	0.55
14	Boiler Coal Bunker	125.0	38.1	67.7	293.0	57.0	17.37	1.40	0.43
15	DR-1 & 2 Steam Tube Dryers	180.0	54.9	164.9	347.0	49.0	14.94	6.00	1.83
16	Dryer Area	126.0	38.4	204.5	369.0	42.0	12.80	3.50	1.07
17	"A" & "B" Calciners	180.0	54.9	400.0	478.0	95.6	29.15	12.00	3.66
18	#1 Coal-Fired Boiler	180.0	54.9	125.3	325.0	58.0	17.68	7.30	2.21
19	#2 Coal-Fired Boiler	180.0	54.9	119.9	322.0	60.0	18.29	7.30	2.21
24	Boiler Ash Silo	25.0	7.6	83.9	302.0	41.0	12.50	1.00	0.30
25	Alkaten Crushing	76.0	23.2	67.7	293.0	48.0	14.63	2.40	0.73
26	DR-3 Alkaten Product Dryer	67.0	20.4	100.1	311.0	58.0	17.68	2.40	0.73
27	Alkaten Product Bagging & Loadout	60.0	18.3	67.7	293.0	62.0	18.90	1.60	0.48
30	Lime Bin #1	88.0	26.8	67.7	293.0	59.0	17.98	0.70	0.20
31	Lime Bin #2	88.0	26.8	67.7	293.0	59.0	17.98	0.70	0.20
33	Sulfur Burner	100.0	30.5	150.0	338.7	34.5	10.52	2.00	0.61
35	Sulfite Dryer	103.0	31.4	128.9	327.0	48.0	14.63	2.30	0.70
36	Sulfite Product Bin #1	60.0	18.3	148.7	338.0	84.9	25.88	0.50	0.15
37	Sulfite Product Bin #2	60.0	18.3	148.7	338.0	84.9	25.88	0.50	0.15
38	Sulfite Product Bin #3	60.0	18.3	148.7	338.0	84.9	25.88	0.50	0.15
44	Lime Unloading	63.0	19.2	67.7	293.0	56.0	17.07	1.00	0.30
46	Ore Transfer Station	12.5	3.8	67.7	293.0	46.0	14.02	2.20	0.67
48	"C" Calciner	180.0	54.9	350.3	450.0	32.0	9.75	10.50	3.20
50	"C" Train Dryer Area	180.0	54.9	199.1	366.0	27.0	8.23	4.50	1.37
51	Product Dryer #5	180.0	54.9	299.9	422.0	33.0	10.06	8.00	2.44
52	Product Silo - Top #2	141.0	43.0	67.7	293.0	50.0	15.24	1.50	0.46
53	Product Silo - Bottom #2	30.0	9.1	67.7	293.0	36.0	10.97	2.80	0.85
54	T-200 Storage Bin	64.2	19.6	67.7	293.0	79.0	24.08	0.60	0.18
62	Carbon Bin	91.0	27.7	67.7	293.0	110.0	33.53	0.50	0.15
63	Perlite Bin	58.0	17.7	67.7	293.0	117.0	35.66	0.50	0.15
66	Carbon/Perlite	20.0	6.1	67.7	293.0	75.0	22.86	1.00	0.30

Source ID	Source Description	Stack Height (ft)	Stack Height (m)	Exit Temperature (F)	Exit Temperature (K)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Exit Diameter (ft)	Exit Diameter (m)
67	Bottom Ash	125.0	38.1	100.1	311.0	33.0	10.06	1.50	0.46
68	Trona Products Bagging Silo	82.0	25.0	67.7	293.0	77.0	23.47	1.20	0.37
70	Sodium Sulfite Bagging Silo	82.0	25.0	67.7	293.0	49.0	14.94	1.30	0.40
71	Metabisulfite Bagging Silo	82.0	25.0	67.7	293.0	49.0	14.94	1.30	0.40
73	Metabisulfite Dryer	95.0	29.0	89.3	305.0	56.0	17.07	2.00	0.61
76	"D" Train Primary Ore Screening	110.0	33.5	67.7	293.0	56.5	17.22	3.70	1.12
79	Ore Transfer Point	68.0	20.7	67.7	293.0	59.9	18.26	2.10	0.63
80	"D" Ore Calciner	180.0	54.9	305.3	425.0	50.8	15.49	10.50	3.20
81	"D" Train Dryer Area	120.0	36.6	249.5	394.0	76.4	23.29	1.70	0.51
82	DR-6 Product Dryer	180.0	54.9	298.1	421.0	43.1	13.15	8.00	2.44
88	Trona Products Transloading #2	11.0	3.4	67.7	293.0	64.0	19.51	1.00	0.30
88b	Trona Products Transloading #3	11.0	3.4	68.0	293.2	63.7	19.40	1.00	0.30
92	Trona Products Bin #2	64.0	19.5	67.7	293.0	85.0	25.91	1.00	0.32
93	Trona Products Rail Loadout	70.0	21.3	67.7	293.0	53.0	16.15	1.00	0.30
94	Sulfite Loadout	90.0	27.4	67.7	293.0	85.0	25.91	1.00	0.32
95	Trona Products Loadout Bin	90.0	27.4	67.7	293.0	85.0	25.91	0.50	0.15
96	T-200 TPX Bin #1	82.0	25.0	67.7	293.0	72.0	21.94	0.80	0.25
97	Soda Ash TPX	82.0	25.0	67.7	293.0	72.0	21.94	0.70	0.20
98	TPX Area	82.0	25.0	67.7	293.0	56.0	17.07	1.50	0.46
99	Crusher Baghouse #2	125.0	38.1	67.7	293.0	50.0	15.24	4.50	1.37
100	Calciner Coal Bunker	126.0	38.4	68.1	293.0	63.7	19.40	1.00	0.30
101	Trona Products Dryer DR-7	120.0	36.6	120.0	322.0	64.0	19.51	3.30	0.99
102	Trona Products Loadout and Silo	120.0	36.6	68.0	293.0	59.0	17.98	1.80	0.53
103	East Ore Reclaim	38.0	11.6	68.0	293.0	91.0	27.74	1.10	0.33
104	West Ore Reclaim	64.0	19.5	68.0	293.0	50.0	15.24	1.30	0.40
105	S-300 Dryer #1	200.0	61.0	154.1	341.0	60.0	18.29	3.00	0.91
106	S-300 Silo and Rail Loadout #1	167.0	50.9	143.3	335.0	15.0	4.57	2.00	0.61
107	S-300 Dryer #2	200.0	61.0	154.0	340.8	60.0	18.29	3.00	0.91
108	S-300 Silo and Rail Loadout #2	172.0	52.4	144.0	335.2	15.0	4.57	2.00	0.61
901	Cooling Tower - High Flow	15.0	4.6	Amb.	0.0	11.7	3.56	27.00	8.23
902	Cooling Tower - Low Flow	6.0	1.8	Amb.	0.0	11.7	3.56	18.00	5.49
E3	Waukesha F18GSI (GVBH compressor)	25.5	7.8	1116.0	875.4	45.6	13.90	1.17	0.36
E4	GM 8.1L (GVBH Pump)	10.8	3.3	1250.0	949.8	--	10.00	0.24	0.07
E5	GM 4.3L (GVBH Pump)	10.8	3.3	1250.0	949.8	--	10.00	0.24	0.07
GVBH Fl	GVB Flare (Gas Incinerator)	22.0	6.7	1800.0	1255.4	52.9	16.12	8.50	2.59
RH	Two (2) Reboiler Heaters	0.3	0.1	95.0	308.2	97.4	29.70	0.55	0.17

Source ID	Source Description	Stack Height		Exit Temperature		Exit Velocity		Exit Diameter	
		(ft)	(m)	(F)	(K)	(ft/s)	(m/s)	(ft)	(m)
KATO	Katolight SENL80FGC4 NG-Fired Generator	11.0	3.4	940.0	777.6	32.8	10.00	0.25	0.08
MV	Mine Vent	8.5	2.6	68.0	293.2	110.1	33.57	17.00	5.18
EG3	Caterpillar 3456 (Emergency Shaft Generator)	8.0	2.4	900.0	755.4	440.1	134.1	0.42	0.13
EG4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	6.8	2.1	975.0	797.0	236.8	72.18	0.50	0.15
EG4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	6.8	2.1	975.0	797.0	236.8	72.18	0.50	0.15
EG4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	6.8	2.1	975.0	797.0	236.8	72.18	0.50	0.15
GND	Generator Engine – C/S Plant	10.0	3.0	500.0	533.2	73.4	22.38	0.17	0.05
GNS1	Steam Plant Generator Engine #1	15.0	4.6	500.0	533.2	176.7	53.87	1.17	0.36
GNS2	Steam Plant Generator Engine #2	15.0	4.6	500.0	533.2	176.7	53.87	1.17	0.36
FRP	Emergency Fire Pump Engine	10.0	3.0	500.0	533.2	76.4	23.29	0.25	0.08
PB	Emergency Pony Boiler	12.0	3.7	500.0	533.2	77.0	23.47	0.83	0.25
Volume Sources					Sy (m)		Sz (M)		
DR	DECA Haul Road Activity***	10.2	3.1		7.04		2.91		
CR	Coal Road Activity***	9.8	3.0		6.19		2.77		
RAIL	Rail Switching Engines***	23.4	7.1		6.53		3.32		
Area Sources					L (m)		W(m)		
DECA	DECA Stockpile/Handling	3.0	0.9		34.08		34.08		

* Flow rate not known, assumed 10 m/s based on conservative combustion engine exhaust.
** Horizontal exhaust without downwash so POINTHOR option was used.
*** Mobile sources characterized as a series of volume sources in lines, with each volume source having the parameters listed in the table.

Figure 7-1. Building and Source Layout at Solvay Facility

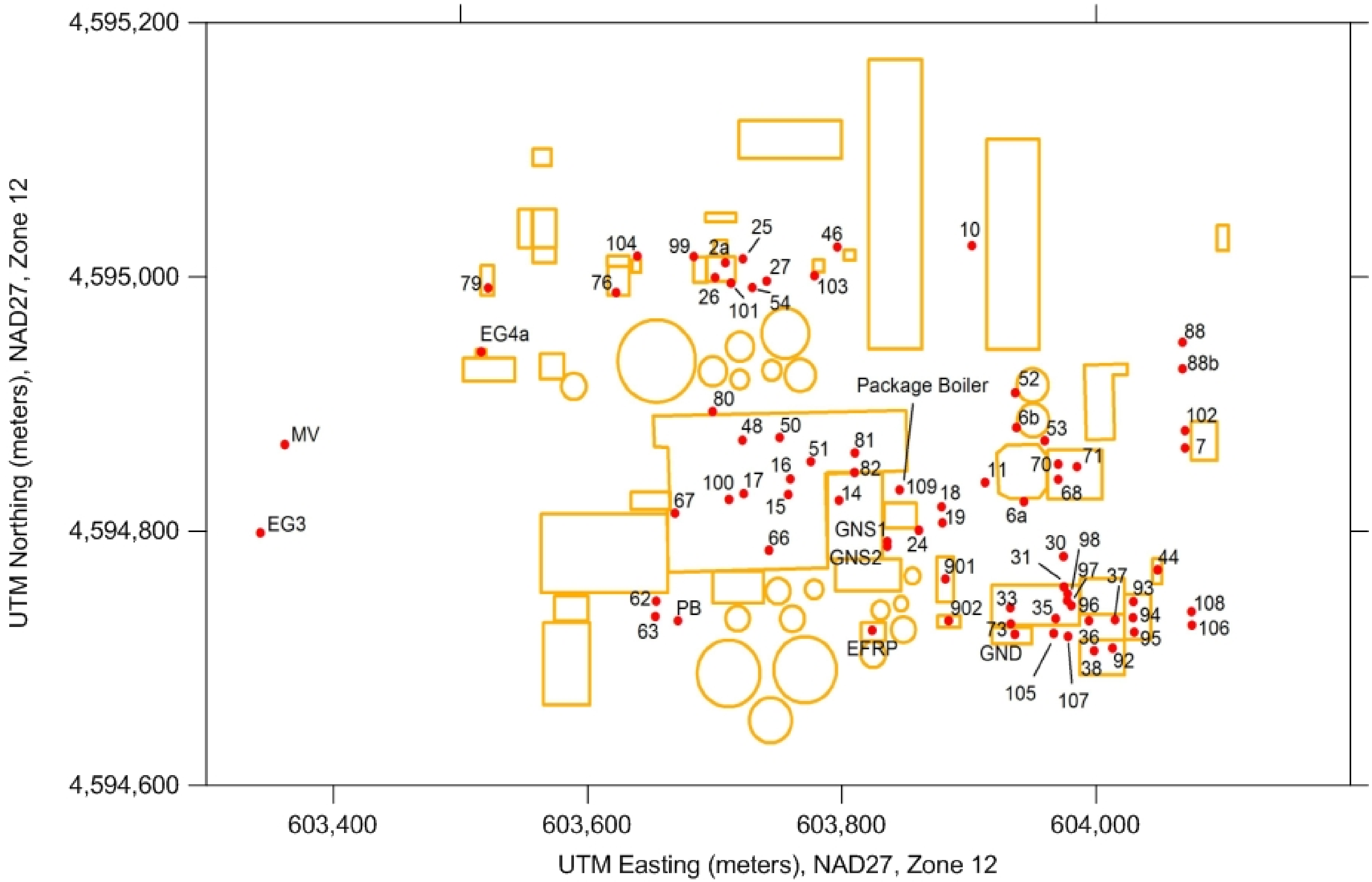

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Figure 7-2. Source Layout at Solvay Facility - Including Mobile Source Locations

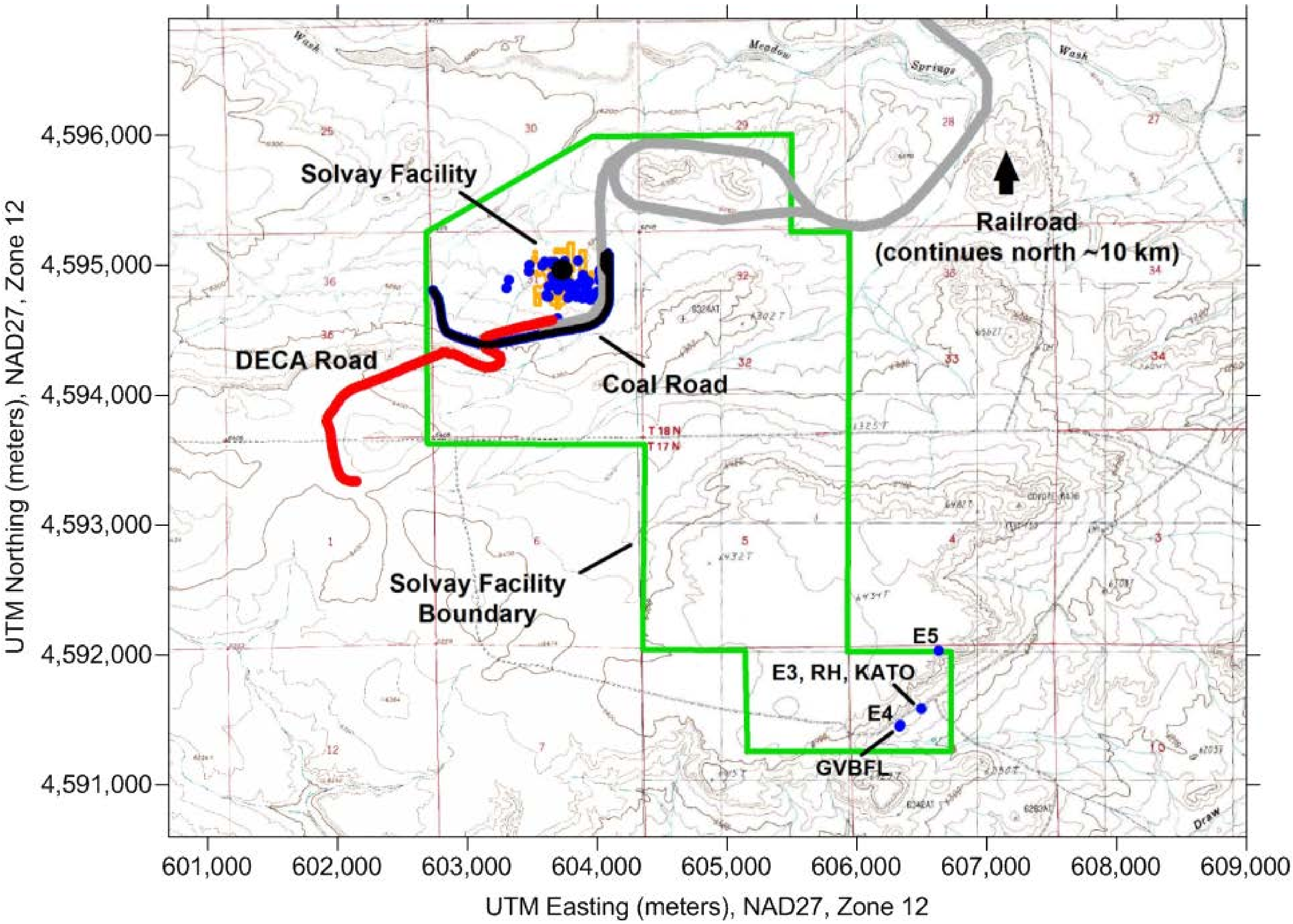

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Table 7-16. Source Coordinates and Elevations

Source ID	Source Description	UTM Coordinates, NAD27, Zone 12 Easting (meters)	Northing (meters)	Elevation (ft)
109	Package Boiler	603828.2	4594847.8	6250
2A	Ore Crusher Building #1	603691.1	4595015.6	6237
6A	Product Silo - Top #1	603925.9	4594839.2	6250
6B	Product Silo - Bottom #1	603920.1	4594893.9	6250
7	Product Loadout Station	604052.8	4594878.5	6250
10	Coal Crushing & Storage	603885.0	4595028.3	6243
11	Coal Transfer Station	603895.4	4594853.3	6250
14	Boiler Coal Bunker	603780.6	4594839.9	6250
15	DR-1 & 2 Steam Tube Dryers	603740.6	4594844.2	6250
16	Dryer Area	603742.3	4594855.8	6250
17	"A" & "B" Calciners	603705.5	4594844.9	6250
18	#1 Coal-Fired Boiler	603861.3	4594835.2	6250
19	#2 Coal-Fired Boiler	603862.0	4594823.4	6250
24	Boiler Ash Silo	603843.1	4594817.8	6250
25	Alkaten Crushing	603704.7	4595018.5	6237
26	DR-3 Alkaten Product Dryer	603683.0	4595004.7	6237
27	Alkaten Product Bagging & Loadout	603723.4	4595002.2	6237
30	Lime Bin #1	603957.1	4594798.5	6257
31	Lime Bin #2	603957.5	4594776.0	6257
33	Sulfur Burner	603915.2	4594760.7	6257
35	Sulfite Dryer	603950.9	4594752.4	6257
36	Sulfite Product Bin #1	603977.2	4594751.0	6257
37	Sulfite Product Bin #2	603997.6	4594751.5	6257
38	Sulfite Product Bin #3	603981.2	4594728.8	6257
44	Lime Unloading	604031.1	4594788.7	6257
46	Ore Transfer Station	603779.2	4595027.4	6237
48	"C" Calciner	603704.5	4594884.5	6250
50	"C" Train Dryer Area	603733.7	4594886.2	6250
51	Product Dryer #5	603758.3	4594868.8	6250
52	Product Silo - Top #2	603919.2	4594919.6	6250
53	Product Silo - Bottom #2	603942.2	4594884.0	6250
54	T-200 Storage Bin	603712.2	4594997.3	6237
62	Carbon Bin	603636.5	4594765.5	6250
63	Perlite Bin	603636.1	4594754.2	6250
66	Carbon/Perlite	603725.6	4594802.9	6250
67	Bottom Ash	603651.3	4594830.5	6250
68	Trona Products Bagging Silo	603952.9	4594855.5	6250
70	Sodium Sulfite Bagging Silo	603952.8	4594866.6	6250
71	Metabisulfite Bagging Silo	603967.7	4594864.7	6250
73	Metabisulfite Dryer	603915.7	4594748.7	6257
76	"D" Train Primary Ore Screening	603605.1	4594993.4	6237
79	Ore Transfer Point	603504.5	4594997.0	6237
80	"D" Ore Calciner	603681.2	4594905.7	6250
81	"D" Train Dryer Area	603793.1	4594875.0	6250
82	DR-6 Product Dryer	603792.8	4594860.6	6250
88	Trona Products Transloading #2	604050.8	4594956.7	6250
88b	Trona Products Transloading #3	604050.8	4594937.2	6257
92	Trona Products Bin #2	603995.6	4594730.6	6257
93	Trona Products Rail Loadout	604012.1	4594765.1	6257
94	Sulfite Loadout	604011.9	4594753.3	6257

Table 7-16. Source Coordinates and Elevations, Contd.

Source ID	Source Description	UTM Coordinates, NAD27, Zone 12 Easting (meters)	Northing (meters)	Elevation (ft)
95	Trona Products Loadout Bin	604012.7	4594742.6	6257
96	T-200 TPX Bin #1	603963.2	4594762.0	6257
97	Soda Ash TPX	603960.1	4594765.6	6257
98	TPX Area	603960.2	4594771.0	6257
99	Crusher Baghouse #2	603666.3	4595020.3	6237
100	Calciner Coal Bunker	603693.8	4594840.6	6250
101	Trona Products Dryer DR-7	603695.6	4595000.6	6237
102	Trona Products Loadout and Silo	604052.7	4594891.5	6250
103	East Ore Reclaim	603761.2	4595006.2	6237
104	West Ore Reclaim	603621.8	4595020.5	6237
105	S-300 Dryer #1	603949.3	4594741.4	6257
106	S-300 Silo and Rail Loadout #1	604058.3	4594747.7	6257
107	S-300 Dryer #2	603960.8	4594739.4	6257
108	S-300 Silo and Rail Loadout #2	604057.8	4594757.7	6257
901	Cooling Tower - High Flow	603864.0	4594781.9	6257
902	Cooling Tower - Low Flow	603866.7	4594750.9	6257
E3	Waukesha F18GSI (GVBH Compressor)	606566.8	4591548.1	6352
E4	GM 8.1L (GVBH Pump)	606403.3	4591421.8	6352
E5	GM 4.3L (GVBH Pump)	606700.5	4592001.3	6440
GVBH Fl	GVB Flare (Gas Incinerator)	606393.3	4591411.8	6309
RH	Two (2) Reboiler Heaters	606566.8	4591548.1	6352
KATO	Katolight SENL80FGC4 NG-Fired Generator	606566.8	4591548.1	6352
MV	Mine Vent	603344.3	4594881.3	6247
EG3	Caterpillar 3456 (Emergency Shaft Generator)	603325.3	4594816.0	6253
EG4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	603499.0	4594949.7	6237
EG4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	603499.0	4594949.7	6237
EG4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	603499.0	4594949.7	6237
GND	Generator Engine – C/S Plant	603918.7	4594740.9	6257
GNS1	Steam Plant Generator Engine #1	603818.5	4594809.3	6253
GNS2	Steam Plant Generator Engine #2	603818.6	4594805.8	6253
FRP	Emergency Fire Pump Engine	603806.5	4594743.7	6257
PB	Emergency Pony Boiler	603653.6	4594750.9	6253
Volume Sources				
DR	DECA Haul Road Activity	Line of 99 volumes (DR001 through DR099); see modeling files.		
CR	Coal Road Activity	Line of 87 volumes (CR001 through CR087); see modeling files.		
RAIL	Rail Switching Engines	Line of volumes (RR001 through RR532); no. of volumes varies based on SIA distance; see modeling files.		
Area Sources				
DECA	DECA Stockpile/Handling	603721.4	4594581.7	6266

7.5 Modeling Methodology

In general, AERMOD was run for the facility, and competing sources (as needed), and the impacts were added to the background concentration for comparison to the WAAQS and NAAQS. For the PSD increment analyses, impacts (without background) were compared to the PSD increments. Section 7.5.5 provides details specific to the 1-hour NO_2 NAAQS modeling analysis.

7.5.1 Model Selection

Per Solvay's approved modeling protocol, the most recent version (12060) of the AERMOD (AMS [American Meteorological Society]/EPA [Environmental Protection Agency] Regulatory Model) was used to estimate the air quality impacts from the Solvay project PM_{10}, $PM_{2.5}$, CO, and NO_X emissions. AERMOD is an advanced modeling system that incorporates the boundary layer theory, turbulence, and effects of terrain features into air dispersion simulations. It is the EPA-recommended guideline model for this type of facility and terrain.

The 12060 version of AERMOD contains PRIME (Plume Rise Model Enhancements) algorithms for downwash calculations. The most recent version of the Building Profile Input Program (BPIP) with PRIME (BPIPPRM, version 04274) was used to calculate building downwash parameters for input to AERMOD.

AERMOD was run using the regulatory default options, except for when specific pollutant evaluations were warranted as a more refined approach (for example, using PVMRM options for 1-hour NO_2).

7.5.2 Meteorological Data

For this analysis, three years (2009–2011) of on-site hourly surface meteorological data from Solvay's 30-meter tower was used as the basis for the meteorological data. Solvay provided an air quality impact modeling protocol (dated July 9, 2012) for WDEQ review prior to the completion of an impact modeling analysis and the submittal of the boiler project PSD permit application to WDEQ. In response to WDEQ's comments on the protocol regarding the methods used to process meteorological data,[35] Solvay submitted a letter and electronic data files to WDEQ on August 10, 2012. A copy of this August 10, 2012, submittal to WDEQ is provided in Appendix J: . On October 11, 2012, WDEQ indicated that review of Solvay's meteorological analysis/data files was complete, and WDEQ provided Solvay with a final set of approved meteorological data files for dispersion modeling.[36]

7.5.3 Receptor Grid

AERMOD requires receptor terrain processing with the AERMAP pre-processor (version 11103) to extract receptor elevations and estimate hill height scale values. AERMAP uses USGS 1-degree and 7.5-minute Digital Elevation Model (DEM) files and National Elevation Dataset (NED) input for this purpose.

[35] E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., RE: Air Quality Impact Modeling Protocol - Solvay, Green River Facility, July 16, 2012.

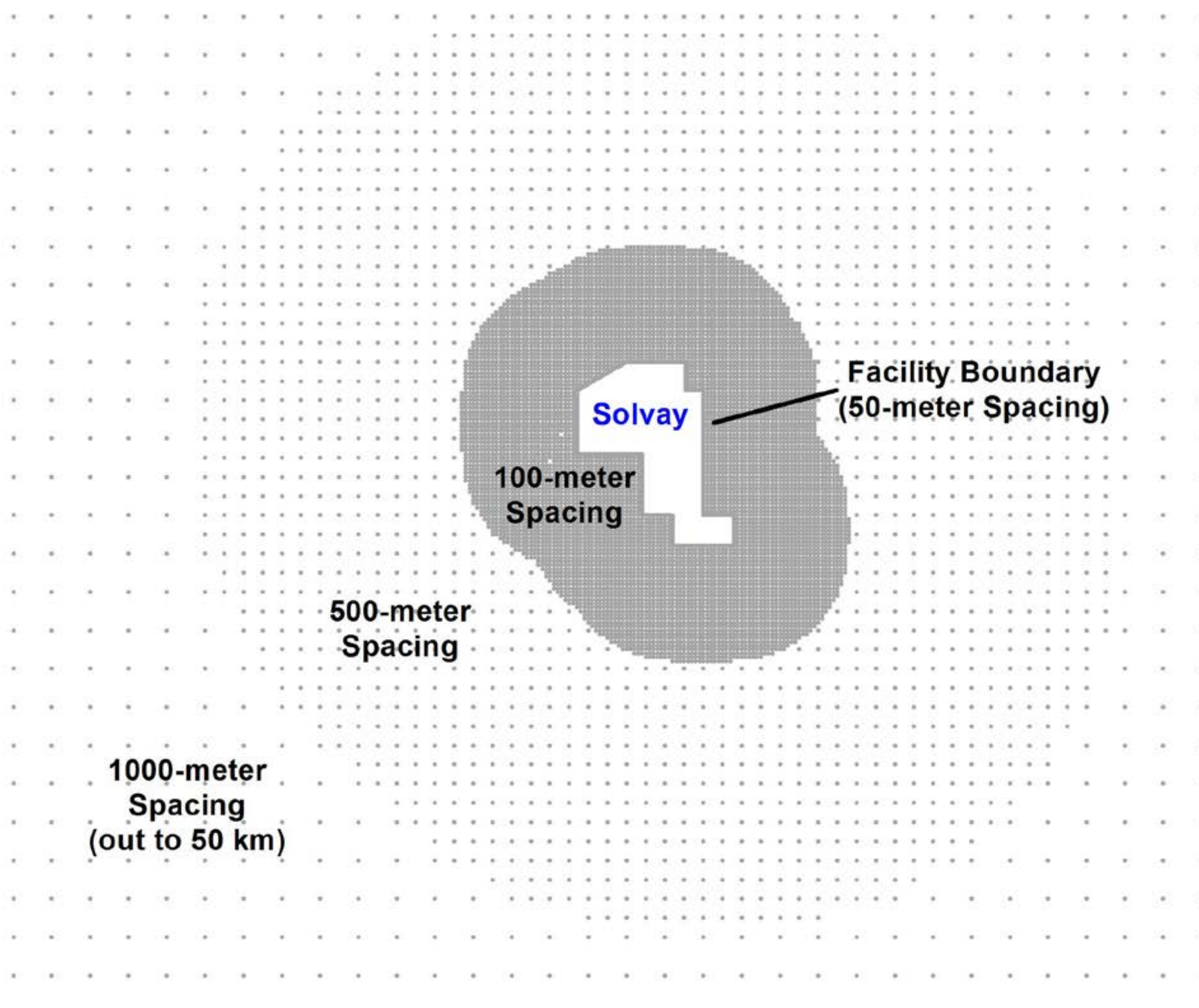
[36] E-mail from D. Watzel, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay meteorological data, October 11, 2012.

AERMAP was run to generate the receptor elevations and hill heights using the NED data. Figure 7-3 provides an overview of the receptor grid used for the impact analysis.

The following receptor grid spacing was used in the modeling analyses:

- 50-meter spacing along the facility's property line when the property line is within 3 kilometers of a source; otherwise 100-meter spacing will be used
- 100-meter spacing between the property line and 3 kilometers from the facility
- 500-meter spacing between 3 kilometers and 10 kilometers from the facility
- 1,000-meter spacing out beyond 10 kilometers as needed to capture the full extent of the significant impact area, with a maximum distance of 50 kilometers.

Figure 7-3. Overview of Receptor Grid Used in the Impact Analysis



7.5.4 Background Concentrations

Table 7-17 shows the background levels utilized for the project. The background values were based on the data gathered from 2009 to 2011. Stations used were Yellowstone and Tata for CO, Murphy Ridge and Moxa for NO_2, Rock Springs for $PM_{2.5}$, and the Solvay on-site upwind monitoring for PM_{10}.

Table 7-17. Background Values Utilized in Impact Analysis

Pollutant	Averaging Period	Monitored Concentration			Background Concentration	Description
		2009	2010	2011		
CO	1-hour (ppm)	2.5	2.1	1.5	2.0	Three-year average of maximum measured value (Yellowstone for 2009 and 2010, Tata in 2011)
CO	8-hour (ppm)	0.8	0.5	1.1	0.8	Three-year average of maximum measured value (Yellowstone for 2009 and 2010, Tata in 2011)
NO_2	1-hour (ppb)	---	---	---	Seasonal/ Diurnal Pairing	Three-year average of the 98th percentile 1-hour maximum (by season and hour of day) - Murphy Ridge for 2009 & 2010, Moxa for 2011
NO_2	Annual (ppb)	1.8	4.7	2.2	2.9	Three-year annual average
Ozone	8-hour (ppb)	60.2	65	65	63.4	Three-year average of the H4H daily 8-hour maximum from Murphy Ridge (2009-2011)
$PM_{2.5}$	24-hour (μg/m^3)	12	13	14.5	13.2	Three-year average of the 98th percentile values measured from Rock Springs
$PM_{2.5}$	Annual (μg/m^3)	6.0	5.9	4.8	5.6	Three-year annual average from Rock Springs
PM_{10}	24-hour (μg/m^3)	57	45	48	57	Maximum 24-hour upwind concentration from 2009-2011 at Solvay
PM_{10}	Annual (μg/m^3)	15	12	10	15	Maximum yearly average of the upwind concentrations from 2009-2011 at Solvay

Sources: EPA AirData Database: http://www.epa.gov/airdata
Wyoming Visibility Monitoring Network: http://www.wyvisnet.com/index.aspx

7.5.5 Overview of EPA Tiered Approach to 1-hour NO_2 Modeling

Currently, the Guideline on Air Quality Models (Guideline), 40 CFR 50, Appendix W, presents a three-tiered approach converting annual NOx impacts to annual NO_2 impacts for comparison to the annual NO_2 NAAQS. In a June 28, 2010, EPA memo[37] and a March 1, 2011, EPA memo[38] providing additional clarifications/guidance on 1-hour NO_2 modeling, the applicability of the Guideline is discussed in the context of modeling for compliance with the new 1-hour NO_2 standard. While the new 1-hour NO_2 NAAQS is defined relative to ambient concentration of NO_2, the majority of NOx emissions for stationary and mobile sources are in the form of Nitric Oxide (NO) rather than NO_2. Given the role of NOx chemistry in determining ambient impact levels of NO_2 based on modeled NOx emissions, the Guideline recommends a three-tiered approach to modeling NO_2 impacts. According to the March 1, 2011 EPA memo, a summary of EPA's three-tiered approach in respect to the 1-hour NO_2 NAAQS is as follows:

- Tier 1: Total conversion of NO to NO_2 – applies to the 1-hour NO_2 standard without any additional justification,
- Tier 2: Multiply Tier 1 result by empirically-derived NO_2/NOx ratio, with 0.80 as the annual national default ratio – may also apply to the 1-hour NO_2 standard in many cases, but some additional consideration will be needed in relation to an appropriate ambient ratio for peak hourly impacts since the current default ambient ratio is considered to be representative of "area wide quasi-equilibrium conditions," and
- Tier 3: "Detailed screening methods" – will continue to be considered on a case-by-case basis for the 1-hour NO_2 standard.

While the Guideline specifically mentions Ozone Limiting Method (OLM) as a detailed screening method under Tier 3, EPA also considers the Plume Volume Molar Ratio Method (PVMRM) discussed under Section 5.1.j of the Guideline to be in this category at this time. Both of these options account for ambient conversion of NO to NO_2 in the presence of ozone.

The OLM and PVMRM methods are both available as non-regulatory default options within the EPA-preferred AERMOD dispersion model. As discussed in Solvay's modeling protocol, the PVMRM code in AERMOD was used for the impact analysis. The PVMRM algorithm is designed to calculate the total NO to NO_2 conversion in combined plumes based on the amount of ozone available. Thus, Solvay has utilized a Tier 3 modeling approach with AERMOD as described below.

[37] Fox, Tyler. EPA – Air Quality Modeling Group. [Memo Regional Air Division Directors]. Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard. June 28, 2010.

[38] Fox, Tyler. EPA – Air Quality Modeling Group. [Memo Regional Air Division Directors]. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard. March 1, 2011.

7.5.5.1 Data Necessary to Utilize PVMRM Chemistry

According to the EPA, key model inputs for the PVMRM options in AERMOD are the in-stack ratios of NO_2/NOx emissions and background ozone concentrations. Solvay has gathered the necessary ambient ozone data (hourly data from the Murphy Ridge monitoring station) and has measured in-stack NO_2/NOx ratios to utilize the PVMRM chemistry in a Tier 3 modeling approach. Recognizing the potential importance of the in-stack NO_2/NOx ratio for hourly NO_2 compliance demonstrations, Solvay has collected in-stack ratios from several larger sources of NOx emissions at the facility (coal-fired calciner, coal-fired boilers, and gas-fired dryer). These measured ratios provide average in-stack NO_2/NOx ratios which were used in the impact analyses. The ratios range from 0.008 for the DR-6 Product Dryer (WDEQ Id. #82; also applied to Product Dryer #5 - WDEQ id. #51) to 0.069 for #1 Coal-Fired Boiler (WDEQ Id. #18).

The NO_2/NOx ratios measured from the recent stack testing program at Solvay are provided in Appendix K: . The assumed in-stack NO_2/NOx ratios utilized in the NO_2 modeling analysis for units with stack test data are provided in Table 7-18. The NO_2/NOx ratios calculated by the MOVES mobile source model were utilized for the DECA Haul Road Activity, Coal Road Activity, and Rail Switching Engines. For all other Solvay sources, the EPA's very conservative, default in-stack NO_2/NOx ratio of 0.5 was utilized.

Table 7-18. **Stack-Tested In-stack Ratios Utilized in the NO_2 Modeling Analysis**

WDEQ Source ID	Source Description	Fuel Type	Test	NO_2 (ppmv)	NO (ppmv)	NOx (ppmv)	NO_2/NOx Ratio
17	"A" & "B" Calciners (CA 1-2)	Coal	R1	5.7	81.8	87.5	0.065
			R2	3.7	83.8	87.5	0.042
			Avg.	---	---	---	**0.054**
18	#1 Coal-Fired Boiler (BO-1)	Coal	R4	17.3	288.4	305.7	0.057
			R5	18.3	297.0	315.2	0.058
			R6	22.5	286.0	308.5	0.073
			R7	22.7	283.2	305.9	0.074
			R8	22.1	286.9	309.0	0.072
			R9	22.6	281.7	304.2	0.074
			R10	23.0	280.4	303.4	0.076
			Avg.	---	---	---	**0.069**
19	#2 Coal-Fired Boiler (BO-2)	Coal	R1	14.8	278.0	292.7	0.050
			R2	16.2	281.6	297.8	0.054
			R3	17.4	280.3	297.6	0.058
			R4	18.7	282.3	301.0	0.062
			R5	18.4	279.2	297.6	0.062
			R6	18.5	280.7	299.2	0.062
			R7	16.2	278.1	294.3	0.055
			R8	16.6	277.5	294.1	0.056
			R9	16.4	274.4	290.7	0.056
			Avg.	---	---	---	**0.057**
82	DR-6 Product Dryer (DR-6)	Natural Gas	R1	0.14	40.8	40.9	0.003
			R2	0.55	41.1	41.7	0.013
			R3	0.37	41.8	42.2	0.009
			Avg.	---	---	---	**0.008**

[1] Assume that the NO_2/NOx ratios from #82 are also applicable to similar gas-fired dryer #51 (Product Dryer #5).

7.5.5.2 Pairing of Modeled Impacts and Background NO_2 Data

In EPA's March 1, 2011, memo regarding 1-hour NO_2 modeling issues, the EPA notes that the form of the 1-hour NO_2 standard has implications regarding appropriate methods for combining modeled ambient concentrations with monitored background concentrations for comparison to the NAAQS in a modeling analysis.

Solvay has utilized EPA's recommendations to incorporate background concentrations in the impact assessment by using multiyear averages of the 98th percentile of the available background concentrations by season and hour-of-day. Consistent with EPA's March 1 memo, the rank associated with the 98th percentile of daily maximum 1-hour values should be consistent with the number of samples within the distribution. Following EPA's guidance in 40 CFR 50, Appendix S, which specifies the rank associated with the 98th percentile values based on the annual number of days with valid data, Solvay has constructed a diurnal NO_2 background profile by season (data from the Murphy Ridge monitor for 2009 and 2010 and Moxa monitor for 2011 through February 2012 to account for three complete winter seasons) which is applied to each hour considered in the modeling analyses. Solvay is defining the seasons here as winter (December through February), spring (March through May), summer (June through August), fall (September through November) so that the 98th percentile background values are determined for each of these seasonal periods. Then, the hourly data from these diurnal background profiles are added to Solvay's modeled NO_2 impacts on an hourly basis to determine a total impact value. Consistent with the form of the 1-hour NO_2 NAAQS, the maximum daily 1-hour NO_2 values are determined from these total hourly values, and the 98th percentile of these maximum daily 1-hour impacts is compared to the 1-hour NO_2 NAAQS.

Table 7-19 provides the diurnal NO_2 background profiles utilized in the modeling analysis.

Table 7-19. Diurnal NO_2 Background Profile Utilized for Solvay Modeling Analysis

	Three-Year Average of 98th Percentile NO_2 Concs. For Use in Modeling (ppb, μg/m³) [1]							
	Winter (Dec.-Feb.)		Spring (Mar.-May)		Summer (Jun.-Aug.)		Fall (Sept.-Nov.)	
Hour	ppb	μg/m³	ppb	μg/m³	ppb	μg/m³	ppb	μg/m³
1	10.2	19.2	8.3	15.6	6.7	12.6	8.8	16.5
2	8.7	16.4	6.8	12.8	6.8	12.8	11.3	21.2
3	10.1	19.0	7.7	14.5	6.6	12.4	9.3	17.5
4	7.3	13.7	7.4	13.9	7.6	14.3	9.5	17.9
5	9.8	18.4	9.0	16.9	7.9	14.9	9.2	17.3
6	8.9	16.7	8.7	16.4	6.7	12.6	10.5	19.7
7	11.4	21.4	7.2	13.5	6.7	12.6	10.1	19.0
8	13.8	25.9	6.7	12.6	6.6	12.4	9.2	17.3
9	9.0	16.9	6.4	12.0	6.3	11.8	7.7	14.5
10	7.9	14.9	5.3	10.0	7.3	13.7	7.0	13.2
11	8.7	16.4	3.5	6.6	5.5	10.3	8.8	16.5
12	7.0	13.2	2.6	4.9	3.6	6.8	5.3	10.0
13	6.1	11.5	2.9	5.5	2.8	5.3	5.8	10.9
14	5.9	11.1	3.0	5.6	2.3	4.3	6.5	12.2
15	7.1	13.3	2.3	4.3	2.1	3.9	4.3	8.1
16	8.7	16.4	2.9	5.5	2.0	3.8	5.8	10.9
17	7.2	13.5	3.0	5.6	2.2	4.1	6.0	11.3
18	9.1	17.1	2.5	4.7	2.5	4.7	5.4	10.2
19	9.9	18.6	3.2	6.0	3.3	6.2	5.6	10.5
20	9.0	16.9	3.3	6.2	3.2	6.0	5.7	10.7
21	10.4	19.6	5.0	9.4	4.0	7.5	7.5	14.1
22	11.1	20.9	5.3	10.0	5.4	10.2	9.3	17.5
23	11.0	20.7	7.0	13.2	6.5	12.2	9.7	18.2
24	10.6	19.9	8.9	16.7	7.7	14.5	9.4	17.7

[1] Based on ambient monitoring data from 2009, 2010, 2011 and January/February 2012.

7.6 Nearby/Competing Sources

If the pollutant impact exceeded the SIL, a full impact analysis was conducted, which included impacts from nearby sources. The package boiler project has significant impacts for NO_2, PM_{10}, $PM_{2.5}$, and CO and a full impacts analysis, including competing sources, was required.

Solvay obtained competing source inventories for PM_{10}, $PM_{2.5}$, CO, and NO_X from WDEQ for sources located within 100 kilometers of the Solvay facility. This inventory was screened to identify the appropriate sources for use in the full impact modeling analysis. A common long-term practice for selecting the “nearby” sources for explicit modeling is to follow a very prescriptive procedure in EPA’s draft New Source Review Workshop Manual (Manual) (EPA 10/1990). If the source is within Solvay's SIA, then it was explicitly modeled. For sources beyond the SIA, a Range of Influence (ROI) from the competing source was determined from the emissions (Q - in TPY) divided by 20 following North Carolina's "20D" approach. The ROI radius for competing sources was limited to 50 kilometers because that is the upper limit of AERMOD's regulatory range. If a competing source's long term ROI overlapped Solvay's long-term SIA, then that competing source was included in the modeling analysis.

Once this competing source inventory was screened, the competing sources were then included in the impact analysis for all pollutants and averaging times that exceeded the SIL. Only receptors within the SIA were evaluated. Tables 7-20 through 7-23 provide the ROI analyses and indicate the facility-wide competing source emissions considered in the full impact analyses. Note that for CO, the emissions information for the four nearby competing trona facilities (Tata/General Chemicals, FMC Westvaco, FMC Granger, and OCI Big Island) was not provided by WDEQ. Solvay obtained this information from the Title V permits for each of the facilities. To be conservative, the CO emissions from these facilities were modeled assuming that all CO facility emissions were emitted from the shortest smokestack at each facility.

Table 7-20. ROI Analysis - $PM_{2.5}$

Company	WDEQ Data Source *	Appx. UTM Coordinate for Competing Source *** Easting(m)	Northing(m)	PM Emissions, Q (tpy)	Appx. Dist. (D) to Solvay $PM_{2.5}$ SIA (km)	Ratio Q/D	Include Facility in Full Modeling?
Bridger Coal Company **	9/18/2012	690,000	4,625,100	23	86.4	0.3	No
Church & Dwight Incorporated	8/20/2012, 9/18/2012	603,615	4,605,010	179	5.2	34.7	**Yes**
Exxon Mobil Corporation (Shute Creek)	8/20/2012	575,603	4,636,887	92	45.6	2.0	No
FMC Wyoming Corporation (Westvaco)	8/20/2012	599,712	4,607,920	3,397	8.7	391.8	**Yes**
FMC Wyoming Corporation (Granger, Caustic Soda)	8/20/2012	591,979	4,613,681	770	17.2	44.8	**Yes**
TATA/General Chemical	8/20/2012	603,700	4,605,000	1,635	5.2	317.2	**Yes**
M-I SWACO	8/20/2012	585,738	4,605,028	1	15.7	0.1	No
Nelson Refining	8/20/2012	586,267	4,604,527	4	14.9	0.3	No
OCI	8/20/2012	608,787	4,618,951	1,129	19.6	57.5	**Yes**
Harborlite	8/20/2012	606,934	4,598,960	12	0.2	53.0	**Yes**

* 8/20/2012 data:

E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., Air Quality Impact Modeling Protocol - Solvay, Green River Facility, August 20, 2012.

9/18/2012 data:

E-mail from D. Watzel, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay NOx, PM, CO regional sources, September 18, 2012.

** No coordinates provided - estimated from Google Earth.

*** Approximate facility coordinates assumed for Q/D analysis; UTM, NAD27, Zone 12.

Table 7-21. ROI Analysis - PM_{10}

Company	WDEQ Data Source *	Appx. UTM Coordinate for Competing Source *** Easting(m)	Northing(m)	PM Emissions, Q (tpy)	Appx. Dist. (D) to Solvay PM_{10} SIA (km)	Ratio Q/D	Include Facility in Full Modeling?
Bridger Coal Company **	9/18/2012	690,000	4,625,100	23	87.5	0.3	No
Church & Dwight Incorporated	8/20/2012, 9/18/2012	603,615	4,605,010	179	6.3	28.6	**Yes**
Exxon Mobil Corporation (Shute Creek)	8/20/2012	575,603	4,636,887	92	46.7	2.0	No
FMC Wyoming Corporation (Westvaco)	8/20/2012	599,712	4,607,920	3,397	9.8	347.7	**Yes**
FMC Wyoming Corporation (Granger, Caustic Soda)	8/20/2012	591,979	4,613,681	770	18.3	42.1	**Yes**
TATA/General Chemical	8/20/2012	603,700	4,605,000	1,635	6.3	261.4	**Yes**
M-I SWACO	8/20/2012	585,738	4,605,028	1	16.8	0.1	No
Nelson Refining	8/20/2012	586,267	4,604,527	4	16.0	0.3	No
OCI	8/20/2012	608,787	4,618,951	1,129	20.7	54.4	**Yes**
Harborlite	8/20/2012	606,934	4,598,960	12	1.3	9.2	No

* 8/20/2012 data:

E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., Air Quality Impact Modeling Protocol - Solvay, Green River Facility, August 20, 2012.

9/18/2012 data:

E-mail from D. Watzel, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay NOx, PM, CO regional sources, September 18, 2012.

** No coordinates provided - estimated from Google Earth.

*** Approximate facility coordinates assumed for Q/D analysis; UTM, NAD27, Zone 12.

Table 7-22. ROI Analysis - Annual NO_2

Company	Facility	WDEQ Data Source *	Appx. UTM Coordinate ** Easting(m)	Northing(m)	NOx Emissions, Q (tpy)	Appx. Dist. (D) to Solvay NO_2 SIA (km)	Ratio Q/D	Include Facility in Full Modeling?
TATA/General Chemical	Green River	8/20/2012 ***	603,680	4,604,958	2,971	5.1	581.1	**Yes**
M-I SWACO	Granger	8/20/2012	585,738	4,605,028	20	15.7	1.3	No
Nelson Refining	Silver Refinery	8/20/2012	586,267	4,604,527	74	14.9	4.9	No
OCI	Big Island	8/20/2012 ***	608,787	4,618,951	1,449	19.6	73.8	**Yes**
AKA Energy	Waterfall CS	8/20/2012	547,068	4,633,545	19	63.6	0.3	No
DCP Midstream	Fossil Ridge GP	8/20/2012	587,220	4,606,693	201	15.3	13.1	No
Mid America Pipeline	Granger	8/20/2012	585,187	4,601,511	52	14.7	3.6	No
MGR	Fabian Ditch CS	8/20/2012	587,380	4,613,100	13	19.5	0.7	No
MGR	Sevenmile Gulch CS	8/20/2012	579,190	4,627,870	36	36.1	1.0	No
Questar	Lateral 1127	8/20/2012	579,944	4,597,879	15	19.0	0.8	No
Saurus	MH-1 CS	8/20/2012	623,100	4,591,000	32	14.8	2.1	No
Williams	Moxa S CS	8/20/2012	575,484	4,605,561	31	25.2	1.2	No
Williams Field Services Company	Hams Fork Compressor Station	8/20/2012, 9/18/2012	564,239	4,635,420	39	51.6	0.8	No
Questar Overthrust Pipeline Company	Roberson Creek Compressor Station	8/20/2012, 9/18/2012	552,975	4,616,052	68	50.0	1.4	No
Enterprise Products	Pioneer Cryogenic Gas Plant	8/20/2012, 9/18/2012	555,698	4,626,564	103	52.5	2.0	No
FMC Wyoming Corporation	FMC Westvaco	8/20/2012 ***	599,196	4,607,679	4,208	8.6	489.2	**Yes**
WGR Operating LP	Granger Gas Plant	8/20/2012, 9/18/2012	587,355	4,599,032	291	11.9	24.5	**Yes**
Questar Overthrust Pipeline Company	CKN-Rock Springs Station	8/20/2012, 9/18/2012	640,179	4,597,951	594	31.6	18.8	No
QEP Field Services Company	Blacks Fork Gas Plant	8/20/2012, 9/18/2012	580,096	4,600,561	372	19.3	19.3	No
FMC Wyoming Corporation	Caustic Soda - Granger	8/20/2012 ***	591,861	4,613,723	2,783	17.3	161.0	**Yes**
Wexpro	Church Butte Central Facility	8/20/2012, 9/18/2012	576,528	4,583,182	58	24.6	2.4	No
Questar Pipeline Company	Eakin Compressor Station	8/20/2012, 9/18/2012	563,325	4,587,935	148	36.0	4.1	No
Church & Dwight Incorporated	Green River Sodium Products Plant	9/18/2012	603,615	4,605,010	65	5.2	12.6	No
Jonah Gas Gathering Company	Bird Canyon Booster Station	9/18/2012	580,497	4,681,302	52	84.5	0.6	No
Westmoreland Kemmerer, Inc.	Kemmerer Mine	9/18/2012	534,346	4,619,651	5	68.7	0.1	No
Williams Field Services Company	Opal Gas Plant	9/18/2012	555,160	4,624,707	576	52.0	11.1	No

Company	Facility	WDEQ Data Source *	Appx. UTM Coordinate ** Easting(m)	Northing(m)	NOx Emissions, Q (tpy)	Appx. Dist. (D) to Solvay NO_2 SIA (km)	Ratio Q/D	Include Facility in Full Modeling?
Questar Exploration & Production Co.	Moxtop 6-1	9/18/2012	574,469	4,621,406	0.4	34.5	0.01	No
Questar Exploration & Production Co.	Reynard 11-1	9/18/2012	572,791	4,621,409	0.5	35.8	0.01	No
XTO Energy Inc	Fontenelle Federal 12-24DX	9/18/2012	572,522	4,673,664	0.2	79.8	0.003	No
BP America Production Company	Whiskey Buttes 201	9/18/2012	573,836	4,627,136	0.2	39.0	0.01	No
Williams Field Services Company	LaBarge Compressor Station	9/18/2012	563,130	4,675,744	45	85.5	0.5	No
Exxon Mobil Corporation	Shute Creek Treating Facility	9/18/2012	575,603	4,636,887	358	45.6	7.9	No
Pacificorp	Naughton Power Plant	9/18/2012	533,478	4,622,736	12,133	70.6	171.9	**Yes**
Imerys Marble, Inc.	White Marble Quarry	9/18/2012	684,990	4,611,390	1.4	78.0	0.02	No
Intermountain Construction and Materials	CT-1216	9/18/2012	699,369	4,604,141	5	91.1	0.1	No
Forest Oil Corporation	Elm Federal 23-12	9/18/2012	600,762	4,694,091	17	94.3	0.2	No
Pacificorp	Jim Bridger Power Plant	9/18/2012	684,046	4,622,971	24,233	80.1	302.5	**Yes**
Wexpro Company	Canyon Creek Compressor Station	9/18/2012	690,764	4,551,336	27	92.3	0.3	No
QEP Field Services Company	Cross Timbers Compressor Station	9/18/2012	578,449	4,664,751	22	69.3	0.3	No
Wexpro Company	Newberger Well 5	9/18/2012	684,990	4,611,390	0.4	78.0	0.01	No
Warren E & P, Inc.	Pacific Rim Generator Station #1	9/18/2012	682,383	4,567,098	11	78.4	0.1	No
Wexpro Company	South Baxter Unit 22	9/18/2012	654,957	4,574,536	3	50.1	0.1	No
Duke Energy Field Services, LP	Cedar Canyon Master Meter	9/18/2012	656,075	4,638,017	0.1	62.9	0.002	No
Anadarko Petroleum Company	Greasewood Wash 10-35	9/18/2012	671,953	4,643,210	0.8	78.6	0.01	No
Samson Resources Company	Leucite Hills 1-33	9/18/2012	658,865	4,633,737	27	62.5	0.4	No
Questar Overthrust Pipeline Company	Point of Rocks Compressor Station	9/18/2012	688,188	4,617,742	54	82.5	0.7	No
Merit Energy Company	Whitney Facility	9/18/2012	509,244	4,588,999	25	89.6	0.3	No

* 8/20/2012 data:

E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., Air Quality Impact Modeling Protocol - Solvay, Green River Facility, August 20, 2012.

9/18/2012 data:

E-mail from D. Watzel, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay NOx, PM, CO regional sources, September 18, 2012.

** Approximate facility coordinates assumed for Q/D analysis; UTM, NAD27, Zone 12.

*** Per T. Martin, Air Sciences Inc. discussion with J. Nall, WDEQ on 10/31/2012, the emissions data provided on 8/20/2012 (not 9/18/2012) are to be utilized for these sources.

Table 7-

Company	Facility	WDEQ Data Source *	Appx. UTM Coordinate ** Easting(m)	Northing(m)	CO Emiss. Q (tpy)	Appx. Dist. (D) to Solvay CO SIA (km)	Ratio Q/D	Include in Full Modeling?
TATA/General Chemical	Green River	Title V Permit ***	603,680	4,604,958	535	9.0	59	**Yes**
OCI	Big Island	Title V Permit ***	608,787	4,618,951	10,683	23.5	454	**Yes**
FMC Wyoming Corporation	FMC Westvaco	Title V Permit ***	599,196	4,607,679	473	12.5	38	**Yes**
FMC Wyoming Corporation	Granger (Soda Ash and Caustic Soda)	Title V Permit ***	591,861	4,613,723	2,603	21.2	123	**Yes**
Williams Field Services Company	Hams Fork Compressor Station	9/18/2012	564,239	4,635,420	38	55.5	1	No
Questar Exploration & Production Co.	Moxtop 6-1	9/18/2012	574,469	4,621,406	0.1	38.4	0.003	No
Questar Exploration & Production Co.	Reynard 11-1	9/18/2012	572,791	4,621,409	0.1	39.7	0.003	No
Questar Exploration & Production Co.	Roberson Creek Compressor Station	9/18/2012	552,975	4,616,052	53	53.9	1	No
Williams Field Services Company	LaBarge Compressor Station	9/18/2012	563,130	4,675,744	56	89.4	1	No
Exxon Mobil Corporation	Shute Creek Treating Facility	9/18/2012	575,603	4,636,887	5,217	49.5	105	**Yes**
Pacificorp	Naughton Power Plant	9/18/2012	533,478	4,622,736	4,979	74.5	67	**Yes**
Enterprise Products	Pioneer Cryogenic Gas Plant	9/18/2012	555,698	4,626,564	58	56.4	1	No
Imerys Marble, Inc.	White Marble Quarry	9/18/2012	684,990	4,611,390	0.3	81.9	0.004	No
Intermountain Construction and Materials	CT-1216	9/18/2012	699,369	4,604,141	84	95.0	1	No
Forest Oil Corporation	Elm Federal 23-12	9/18/2012	600,762	4,694,091	6	98.2	0.1	No
WGR Operating LP	Granger Gas Plant	9/18/2012	587,355	4,599,032	86	15.8	5	No
Pacificorp	Jim Bridger Power Plant	9/18/2012	684,046	4,622,971	25,610	84.0	305	**Yes**
Questar Overthrust Pipeline Co.	CKN-Rock Springs Station	9/18/2012	640,179	4,597,951	416	35.5	12	No
QEP Field Services Company	Blacks Fork Gas Plant	9/18/2012	580,096	4,600,561	80	23.2	3	No
Wexpro Company	Canyon Creek Compressor Station	9/18/2012	690,764	4,551,336	43	96.2	0.4	No
QEP Field Services Company	Cross Timbers Compressor Station	9/18/2012	578,449	4,664,751	16	73.2	0.2	No
Wexpro Company	Newberger Well 5	9/18/2012	684,990	4,611,390	0.4	81.9	0.0	No
Warren E & P, Inc.	Pacific Rim Generator Station #1	9/18/2012	682,383	4,567,098	11	82.3	0.1	No
Wexpro Company	South Baxter Unit 22	9/18/2012	654,957	4,574,536	5	54.0	0.1	No
Duke Energy Field Services, LP	Cedar Canyon Master Meter	9/18/2012	656,075	4,638,017	0.1	66.8	0.0	No
Anadarko Petroleum Company	Greasewood Wash 10-35	9/18/2012	671,953	4,643,210	2	82.5	0.0	No
Samson Resources Company	Leucite Hills 1-33	9/18/2012	658,865	4,633,737	9	66.4	0.1	No
Questar Overthrust Pipeline Co.	Point of Rocks Compressor Station	9/18/2012	688,188	4,617,742	55	86.4	1	No
Merit Energy Company	Whitney Facility	9/18/2012	509,244	4,588,999	15	93.5	0.2	No
Wexpro	Church Butte Central Facility	9/18/2012	576,528	4,583,182	3	28.5	0.1	No
Questar Pipeline Company	Eakin Compressor Station	9/18/2012	563,325	4,587,935	35	39.9	1	No

* 8/20/2012 data: E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., Air Quality Impact Modeling Protocol - Solvay, Green River Facility, August 20, 2012.
9/18/2012 data: E-mail from D. Watzel, WDEQ, to T. Martin, Air Sciences Inc., RE: Solvay NOx, PM, CO regional sources, September 18, 2012.

** Approximate facility coordinates assumed for Q/D analysis; UTM, NAD27, Zone 12.

*** Per T. Martin, Air Sciences Inc. discussion with J. Nall, WDEQ on 10/31/2012, CO emissions from these facilities to be used in the modeling analyses are based on Title V permits; http://deq.state.wy.us/aqd/TitleVPermitsIssued.asp;
to be conservative these emissions are modeled out of the shortest smokestack at each trona facility

7.6.1 Competing Sources: $PM_{2.5}$ Increment

Note that because the major source baseline date for $PM_{2.5}$ is October 20, 2010, only changes at the competing source facilities since this date consume $PM_{2.5}$ increment. As shown in Table 7-20 above, there were six competing sources which did not screen out of the ROI analysis for $PM_{2.5}$ modeling. Of these six facilities, two facilities (Church and Dwight and Harborlite) are not major PSD sources. Because the $PM_{2.5}$ minor source baseline date has not been triggered in Solvay's Air Quality Control Region (AQCR), any changes prior to the minor source baseline date do not consume increment. Thus, these two minor sources don't consume increment and are not included in the $PM_{2.5}$ increment analysis.

Solvay has also inquired with WDEQ regarding which specific source units at the four nearby competing trona facilities consume $PM_{2.5}$ increment. According to WDEQ, OCI Big Island has not had any significant permitting actions since the $PM_{2.5}$ major source baseline date and thus does not consume increment. As for increment-consuming sources associated with recent proposed changes at FMC Granger (WDEQ has received a PSD permit application from FMC), WDEQ has indicated that it has not reviewed modeling files or deemed that application complete at this time, so it is assumed for the purposes of this Solvay modeling analysis that FMC Granger does not consume $PM_{2.5}$ increment.

At FMC Westvaco and TATA/General Chemical, there have been a few permitting actions since the major source baseline date which affect roughly 18 sources at these two facilities. On November 9, 2012, WDEQ provided Solvay the $PM_{2.5}$ increment inventory for these sources. These sources were included in Solvay's full $PM_{2.5}$ increment analysis. [39]

7.6.2 Competing Sources: 1-hour NO_2 NAAQS

For the 1-hour NO_2 analysis, an additional review was conducted to determine the SIA. EPA recently clarified that "following such [Manual] procedures in a literal and uncritical manner may in many cases result in cumulative impact assessments that are overly conservative" (EPA 03/11).[40] The Guideline on Air Quality Models (40 CFR 51, Appendix W) is consistent with this approach, stating that professional judgment is required for ascertaining which sources should be explicitly modeled and which sources can be represented through ambient monitoring data. Per Section 8.2.3 of Appendix W, "all sources expected to cause a significant concentration gradient in the vicinity of the [applicant's source] should be explicitly modeled." As mentioned in EPA's guidance and in the Guideline on Air Quality Modeling (40 CFR 51, Appendix W), the EPA considers whether a regional source causes "a significant concentration gradient in the vicinity of the source" under consideration (i.e., Solvay) as the main criterion for determining if a regional source should be included in a full impact analysis.

Given the issues and challenges arising from the implementation of the 1-hour NO_2 standard, EPA has offered some additional explanation in the March 1, 2011 memo regarding what this guidance means and

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39 E-mail from J. Nall, WDEQ, to T. Martin, Air Sciences Inc., Solvay PSD: PM-2.5 Increment Sources, November 9, 2012.

40 EPA OAQPS. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard*. From Tyler Fox, Leader – Air Quality Monitoring Group, C439-01, March 1, 2011.

how it should be applied. In discussing specifically issues of terrain influences on the location and gradients of maximum 1-hour concentrations, the EPA states that:

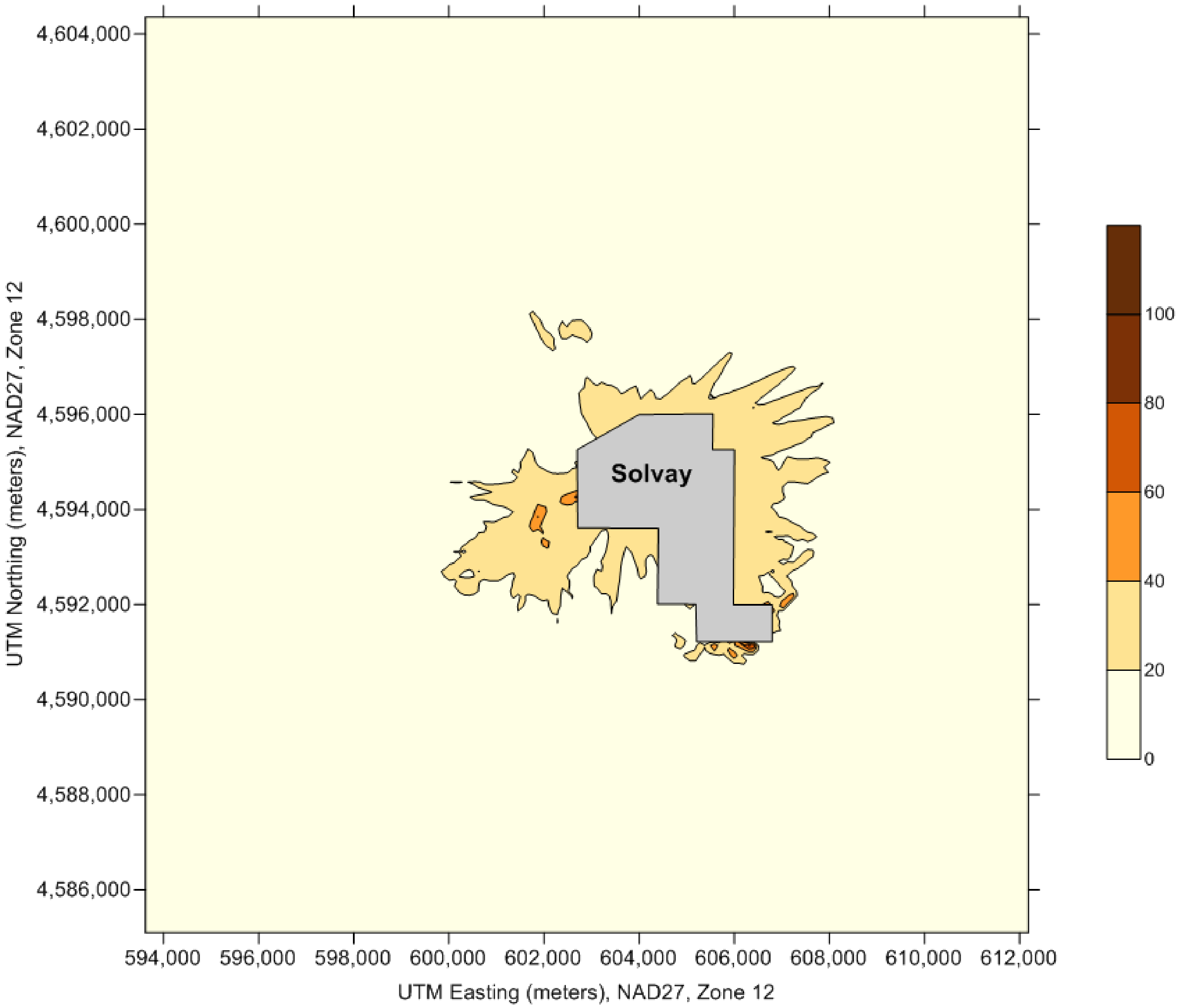
> …"*Even accounting for some terrain influences on the location and gradients of maximum 1-hour concentrations, these considerations suggest that the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 kilometers of the project location in most cases. The routine inclusion of all sources within 50 kilometers of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases.*"

This does not mean that a distant source could not have an overlapping impact. Rather, it suggests that this overlapping impact can be addressed using available monitoring data and incorporated in the background concentration, rather than by explicitly modeling the distant source.

Solvay has evaluated the significant 1-hour NO_2 concentration gradient for the Solvay boiler project to determine the need to include competing sources in the full 1-hour NO_2 NAAQS analyses. Figure 7-4 shows a contour plot of the SIA impacts for 1-hour NO_2 and indicates that modeled concentrations decrease significantly approximately four kilometers from the facility. Solvay has further evaluated the significant concentration gradient to the west of the Solvay facility in an area of higher, localized 1-hour NO_2 impacts and to the north towards the nearest nearby competing source (Tata/General Chemicals). Figure 7-5 illustrates the change in 1-hour NO_2 concentration as a function of distance from the Solvay facility and shows that concentrations level off and change less rapidly from point to point at around five kilometers or less from the facility. Therefore, Solvay defines its significant concentration gradient as 5 km for 1-hour NO_2.

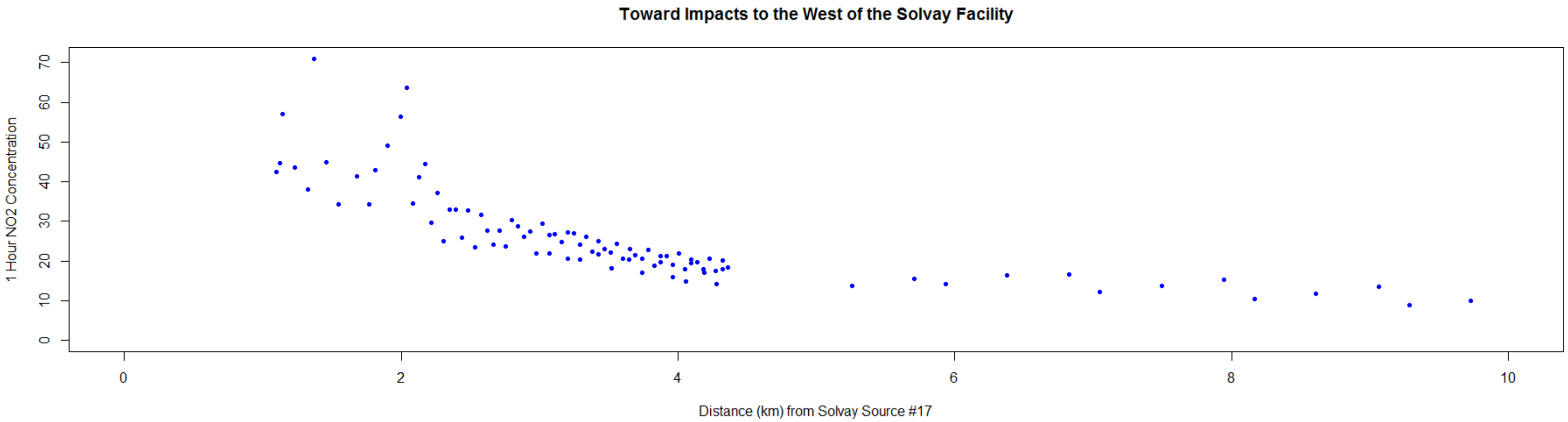
Figure 7-6 shows the locations and annual NO_2 emissions of the competing facilities located in the vicinity of the Solvay; the location of the NO_2 monitoring station, Moxa, is also provided. The competing sources which did not screen out of the traditional annual NO_2 ROI analyses as shown in Table 7-22 were analyzed in conjunction with EPA guidance on 1-hour NO_2 modeling to determine if the facility was to be explicitly modeled or if the facility was assumed represented by background concentrations. Solvay primarily relied on EPA guidance which considers the significant concentration in the vicinity of Solvay, generally within about 10 km of the Solvay facility, as the criteria for inclusion of a competing source in the 1-hour NO_2 analysis. As shown on Figure 7-6, there is a smaller facility located to the west of Solvay (WGR Granger). This smaller facility has NO_2 emissions which are a small fraction (< 10 percent) of the larger trona facilities, including Solvay and thus its significant concentration gradient is small. This source was not expected to impact Solvay's concentration gradient and was not explicitly modeled; the impact from this small facility was assumed to be accounted for in the background concentration.

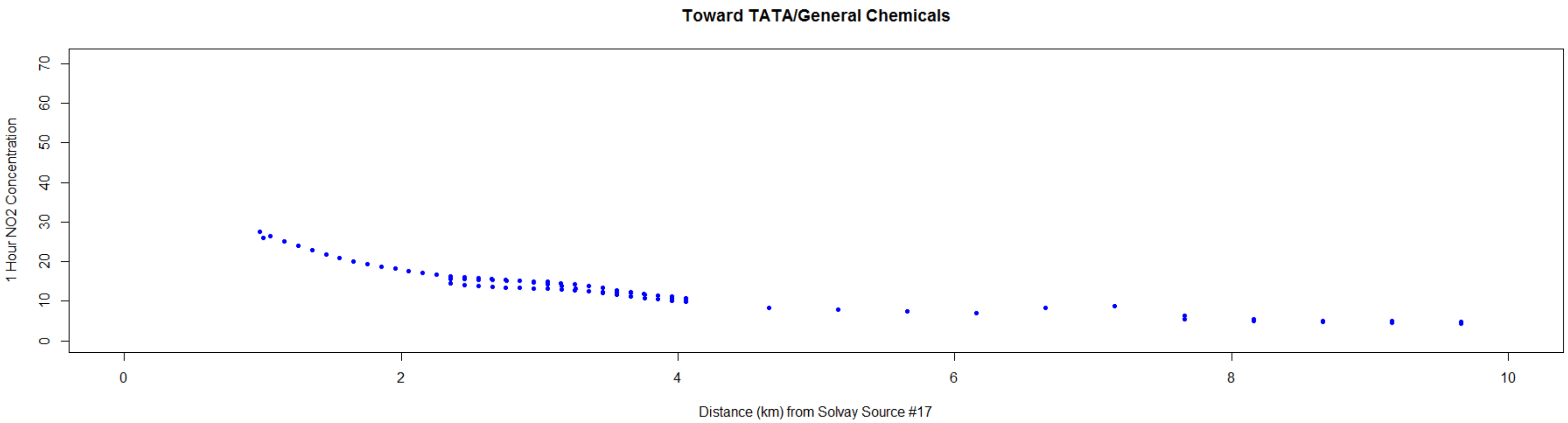
Figure 7-4. Contour Plot of 1-hour NO_2 SIA Impacts in Vicinity of Solvay Facility



SOLVAY2016_1.2_000713

Figure 7-5. 1-hour NO_2 Concentration Gradient Plots

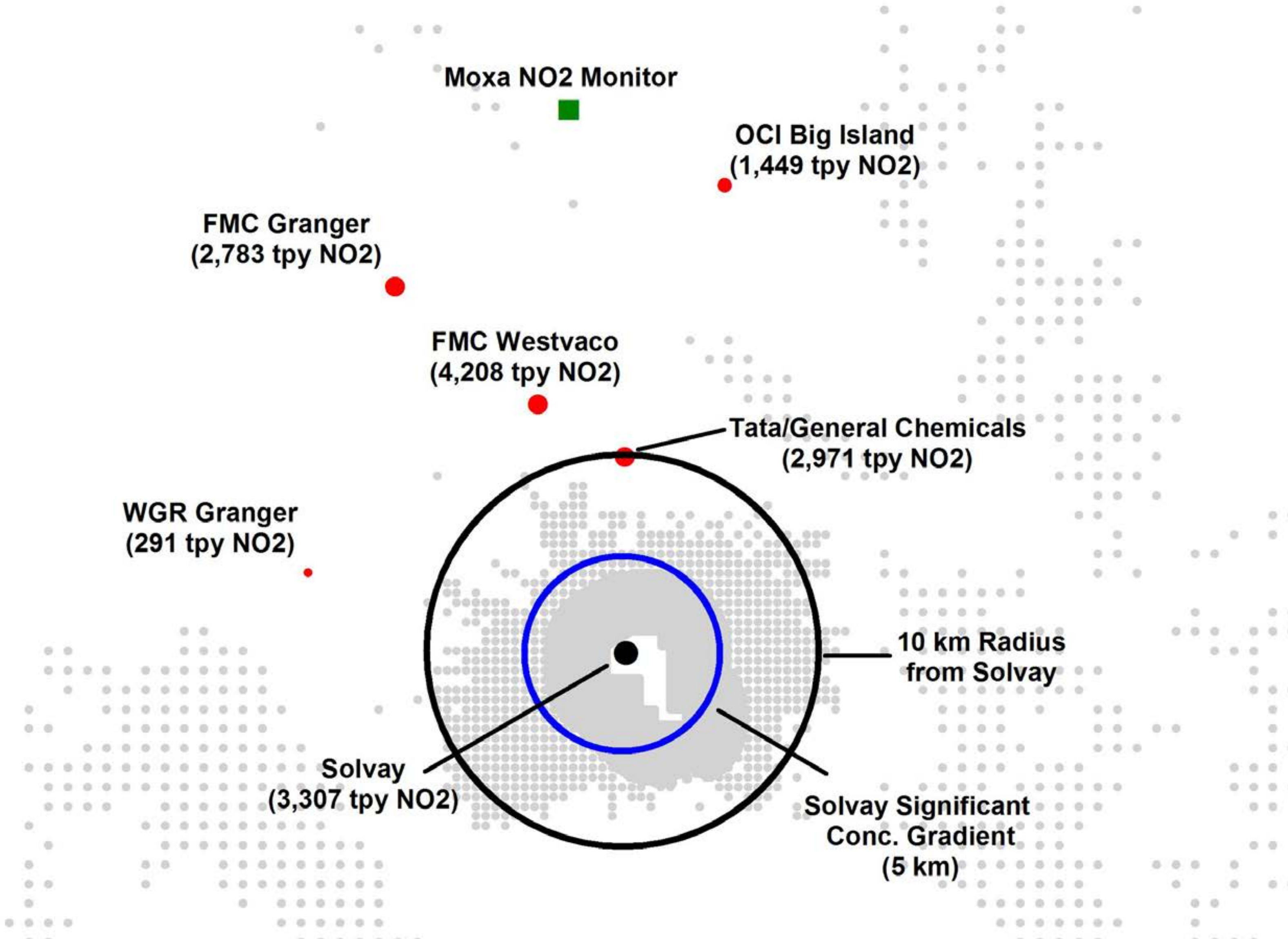




SOLVAY2016_1.2_000714

Figure 7-6. Map Showing Competing Sources and the NO_2 Background Monitor in the Vicinity of Solvay

(gray points on the figure are the 1-hour NO_2 receptors where impacts exceed the preliminary 1-hour NO_2 SIL value of 7.5 μg/m^3)



SOLVAY2016_1.2_000715

As shown on Figure 7-6 there are also several larger trona facilities (FMC Westvaco, FMC Granger, Tata/General Chemicals, and OCI Big Island) located to the north of Solvay. For reference, the Solvay concentration gradient is five kilometers based on facility emissions of around 3,300 tpy NO_2 emissions. FMC Granger has annual NO_2 emissions of around 2,800 tpy, about the level of the Solvay facility. Thus, the FMC Granger significant concentration gradient is assumed to be on the order of Solvay's significant concentration gradient of 5 km. The FMC Granger facility is located 17 kilometers from the edge of Solvay's significant concentration and its significant concentration gradient is not expected to overlap with Solvay's significant concentration gradient. The OCI Big Island facility emits less than half the annual NO_2 emissions of the Solvay facility and is located more than 19 kilometers from the Solvay facility and is also is not expected to overlap with Solvay's significant concentration gradient. Both FMC Granger and OCI Big Island facilities are located closer to the Moxa NO_2 monitor (12 km and 8 km, respectively) than to the nearest edge of the Solvay concentration gradient. These facilities impact the NO_2 monitor and were assumed included in the background concentration and were not explicitly modeling in the full impact modeling analysis.

The FMC Westvaco (4,208 tpy) and Tata/General Chemicals (2,971 tpy) facilities are located roughly 8.5 km and 5 km from the Solvay facility's significant concentration gradient, respectively. Given the NO_2 emissions from Tata/General Chemicals, roughly equal to Solvay's emissions, the significant concentration gradient from this facility is expected to be at least 5 km which overlaps Solvay's significant concentration gradient. The significant concentration gradient from the FMC Westvaco facility is expected to be more than 5 km (perhaps on the order of 6 to 7 km when considering the ratio of FMC Westvaco facility emissions to Solvay facility emissions) which doesn't overlap Solvay's significant concentration gradient, but is close. Therefore, these two facilities were explicitly modeled in the full 1-hour NO_2 NAAQS analysis. Following EPA guidance, a receptor grid consisting of only those receptors which exceeded the 7.5 $\mu g/m^3$ interim SIL level (from the 1-hour NO_2 SIA analysis) was utilized for the full 1-hour NO_2 NAAQS analysis.

Solvay has reviewed the NOx source inventory at FMC Westvaco and Tata/General Chemicals and determined that these facilities have some similar sources to those at the Solvay facility (e.g., coal boilers, combustion/mobile/heavy machinery). Therefore, as shown in Table 7-24, Solvay has applied its NO_2/NOx ratios to these selected competing sources for full 1-hour NO_2 modeling. Note that the competing facilities also utilize large natural gas-fired boilers and there are NO_2/NOx ratio values available from the literature for these types of sources.[41] Solvay asserts that the NO_2/NOx ratio value of 0.1 from the literature is conservative as it is much larger than Solvay's measured stack test data value of 0.008 for its large natural gas-fired combustion source (#82; DR-6 Product Dryer, 200 MMBtu/hr). For all other competing sources, EPA's very conservative default in-stack NO_2/NOx ratio of 0.5 was utilized.

[41] We Energies, Rothschild, Wisconsin:
https://www.we-energies.com/environmental/biomass/airqualityimpactanalysis_appendix_e.pdf
San Joaquin Valley Air Quality Control District:
http://www.valleyair.org/busind/pto/tox_resources/Assessment%20of%20Non-Regulatory%20Option%20in%20AERMOD.pdf

Table 7-24. In-stack NO_2/NOx Ratios for Selected Competing Sources

WDEQ Source ID	Source Description	Source Type	NO_2/NOx Ratio
FMC Westvaco			
NS1A	Mono #6 Coal/Gas Fired Boiler	Coal Boiler	0.1
NS1B	Mono #7 Coal/Gas Fired Boiler	Coal Boiler	0.1
PH1A	Sesqui #1 Gas-fired Boiler	Gas Boiler	0.1
PH1B	Sesqui #2 Gas-fired Boiler	Gas Boiler	0.1
PH2	Sesqui #3 Gas-fired Boiler	Gas Boiler	0.1
PH3	Sesqui #4 Gas-fired Boiler	Gas Boiler	0.1
MW5	#8 Gas-fired Boiler	Gas Boiler	0.1
MINVENT2	Mine Vent 2	Combustion/Mobile/Heavy Machinery	0.11
MINVENT3	Mine Vent 3	Combustion/Mobile/Heavy Machinery	0.11
MINVENT4	Mine Vent 4	Combustion/Mobile/Heavy Machinery	0.11
MINVENT6	Mine Vent 6	Combustion/Mobile/Heavy Machinery	0.11
MINVENT9	Mine Vent 9	Combustion/Mobile/Heavy Machinery	0.11
SESQPILE	Sesqui Pile Loading/Dozing	Combustion/Mobile/Heavy Machinery	0.11
MONOPILE	Mono Pile Loading/Dozing	Combustion/Mobile/Heavy Machinery	0.11
COALPILE	Coal Pile Unloading/Adding Mat./Dozing	Combustion/Mobile/Heavy Machinery	0.11
PLANTMBL	Plant Mobile Source Tailpipe	Combustion/Mobile/Heavy Machinery	0.11
RAIL1 - 6	Rail	Combustion/Mobile/Heavy Machinery	0.11
Tata/General Chemicals			
GCCP34	C Boiler	Coal Boiler	0.1
GCCP55	D Boiler	Coal Boiler	0.1
GCCP56	E Boiler	Gas Boiler	0.1
GCCP58	Mine Shaft #1	Combustion/Mobile/Heavy Machinery	0.11
GCCP59	Mine Shaft #5	Combustion/Mobile/Heavy Machinery	0.11

7.7 Modeling Results

7.7.1 Preliminary Analysis Results

Initially, the SIA is determined for every relevant averaging time for a particular pollutant as shown in Table 7-25. The final SIA for that pollutant is the largest area for each of the various averaging times. According to the EPA's Draft New Source Review Workshop Manual (EPA, 1990), the SIA is a circular area with a radius extending from the source to: 1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or 2) a modeling receptor distance of 50 kilometers, whichever is less. Therefore, a SIA cannot be greater than 50 kilometers for any pollutant. For the 1-hour NO_2 SIA, following EPA guidance, the receptors to be considered for the 1-hour NO_2 analysis are based on the explicit receptors which have a three year average impact greater than 7.5 $\mu g/m^3$, rather than a traditional impact area based on a circular radius.

AERMOD was run for the project (package boiler and debottlenecked sources) and contemporaneous sources (as identified in Table 7-2) for each pollutant and averaging time for the SIA analyses.

Table 7-25 provides the Class II SIAs from the package boiler project and indicates SIAs of 5.0 km for NO_2 (annual), 5.0 km for $PM_{2.5}$, 3.9 km for PM_{10}, and 1.1 km for CO. The results of the full impact modeling analyses utilizing these SIAs are provided in Section 7.7.2.

Table 7-25. Class II Significant Impact Areas for Package Boiler Project

Pollutant	Averaging Period	Max. Modeled Impact (μg/m³)	Class II SIL (μg/m³)	Significant Impact?	SIA Distance (km)	SIA Receptor [1] UTM_Easting (m)	SIA Receptor [1] UTM_Northing (m)
Nitrogen Dioxide (NO_2)	1-hour [2]	115.5	7.5	Yes	1-hour NO_2 SIA Receptors	N/A	N/A
	Annual [4]	5.5	1	Yes	**5.0**	607,300.0	4,591,500.0
Fine Particulate Matter ($PM_{2.5}$)	24-hour [3]	3.0	1.2	Yes	3.9	607,100.0	4,593,000.0
	Annual [3]	1.5	0.3	Yes	**5.0**	608,600.0	4,594,100.0
Particulate Matter (PM_{10})	24-hour [4]	4.6	5	No	Not Sig.	---	---
	Annual [4]	10.0	1	Yes	**3.9**	607,500.0	4,594,300.0
Carbon Monoxide (CO)	1-hour [4]	1,938	2,000	No	Not Sig.	---	---
	8-hour [4]	546	500	Yes	**1.1**	603,782.7	4,595,874.7

[1] UTM, NAD27, Zone 12 coordinates; SIA is measured from Source #17 which is the largest emitting source in the SIA analysis.

[2] For the 1-hour NO_2, the explicit receptors above the preliminary 1-hour NO_2 SIL are considered in the full NAAQS analysis.

[3] For $PM_{2.5}$, the average of the maximum modeled impacts averaged over three years on a receptor-by-receptor basis is utilized to determine the SIA.

[4] For these pollutants and averaging periods, the maximum modeled concentrations are used to determine the SIAs.

7.7.2 Full Impact Modeling Results

A summary of the maximum modeled impacts from the Solvay facility for comparison to the WAAQS/NAAQS and PSD increments are provided in Tables 7-26 and 7-27. These results show that the Solvay facility and its proposed package boiler project will comply with these ambient standards.

Note that all maximum NAAQS and increment impacts are located close to the Solvay facility on the ambient air boundary or within a kilometer of the ambient air boundary as shown in Figures 7-7 and 7-8.

The AERMOD and BPIP model input and output files, meteorological data files, and other related documentation are provided on the attached compact disk.

Table 7-26. Summary of Maximum Modeled Impacts – NAAQS/WAAQS Analysis

Pollutant	Averaging Period	Max. Impact Receptor [1] UTM_Easting (m)	UTM_Northing (m)	Concentration ($\mu g/m^3$) Modeled	Background	Total	NAAQS/ WAAQS ($\mu g/m^3$)	Exceed NAAQS/ WAAQS?
Nitrogen Dioxide (NO_2)	1-hour [2]	601,900.0	4,593,800.0	160.1	N/A [6]	160.1	189	No
	Annual [3]	606,200.0	4,595,300.0	8.8	5.5	14.3	100	No
Fine Particulate Matter ($PM_{2.5}$)	24-hour [4]	606,700.0	4,593,300.0	17.3	13.2	30.5	35	No
	Annual [7]	606,800.0	4,594,900.0	5.8	5.6	11.4	15	No
Particulate Matter (PM_{10})	24-hour [5]	606,000.0	4,593,400.8	27.7	57	84.7	150	No
	Annual [3]	602,600.0	4,594,200.0	13.7	15	28.7	50	No
Carbon Monoxide (CO)	1-hour [5]	603,300.0	4,595,800.0	2,390	2,289	4,679	40,000	No
	8-hour [5]	603,566.2	4,595,749.7	793	916	1,709	10,000	No

[1] UTM, NAD27, Zone 12 coordinates.

[2] Modeled value presented is the highest-eighth-highest max. daily 1-hour value averaged over three-years on a receptor-by-receptor basis.

[3] Highest modeled annual average concentration over three years.

[4] Three-year average of the highest-first-highest max. daily modeled concentrations on a receptor-by-receptor basis.

[5] Highest-second-highest modeled concentrations.

[6] Diurnal background concentrations already accounted for in modeled impacts (i.e., AERMOD sums the hourly modeled impacts and background concentrations within the model code).

[7] Three-year average of the annual modeled concentrations on a receptor-by-receptor basis.

Table 7-27. Summary of Maximum Modeled Impacts – PSD Increment Analysis

Pollutant	Averaging Period	Max. Impact Receptor [4] UTM_Easting (m)	UTM_Northing (m)	Max. Modeled Impact Without Background Concentration (µg/m³)	PSD Class II Increment (µg/m³)	Exceed Increment?
Nitrogen Dioxide (NO_2)	1-hour	NA [2]	NA [2]	NA [2]	NE [3]	NA [2]
	Annual	606,200.0	4,595,300.0	8.8	25	No
Fine Particulate Matter ($PM_{2.5}$)	24-hour [1]	603,566.2	4,595,749.7	2.1	9	No
	Annual	606,000.0	4,594,500.8	0.6	4	No
Particulate Matter (PM_{10})	24-hour [1]	606,000.0	4,593,400.8	27.7	30	No
	Annual	602,600.0	4,594,200.0	13.7	17	No
Carbon Monoxide (CO)	1-hour	NA [2]	NA [2]	NA [2]	NE [3]	NA [2]
	8-hour	NA [2]	NA [2]	NA [2]	NE [3]	NA [2]

[1] Presented as the highest-second-highest value, consistent with 40 CFR 52.21(c) for impact comparisons to the short-term PSD increments.

[2] NA = Not applicable.

[3] NE = Not established.

[4] UTM, NAD27, Zone 12 coordinates.

Figure 7-7. Map of Locations of Maximum Modeled Impacts from NAAQS Analysis

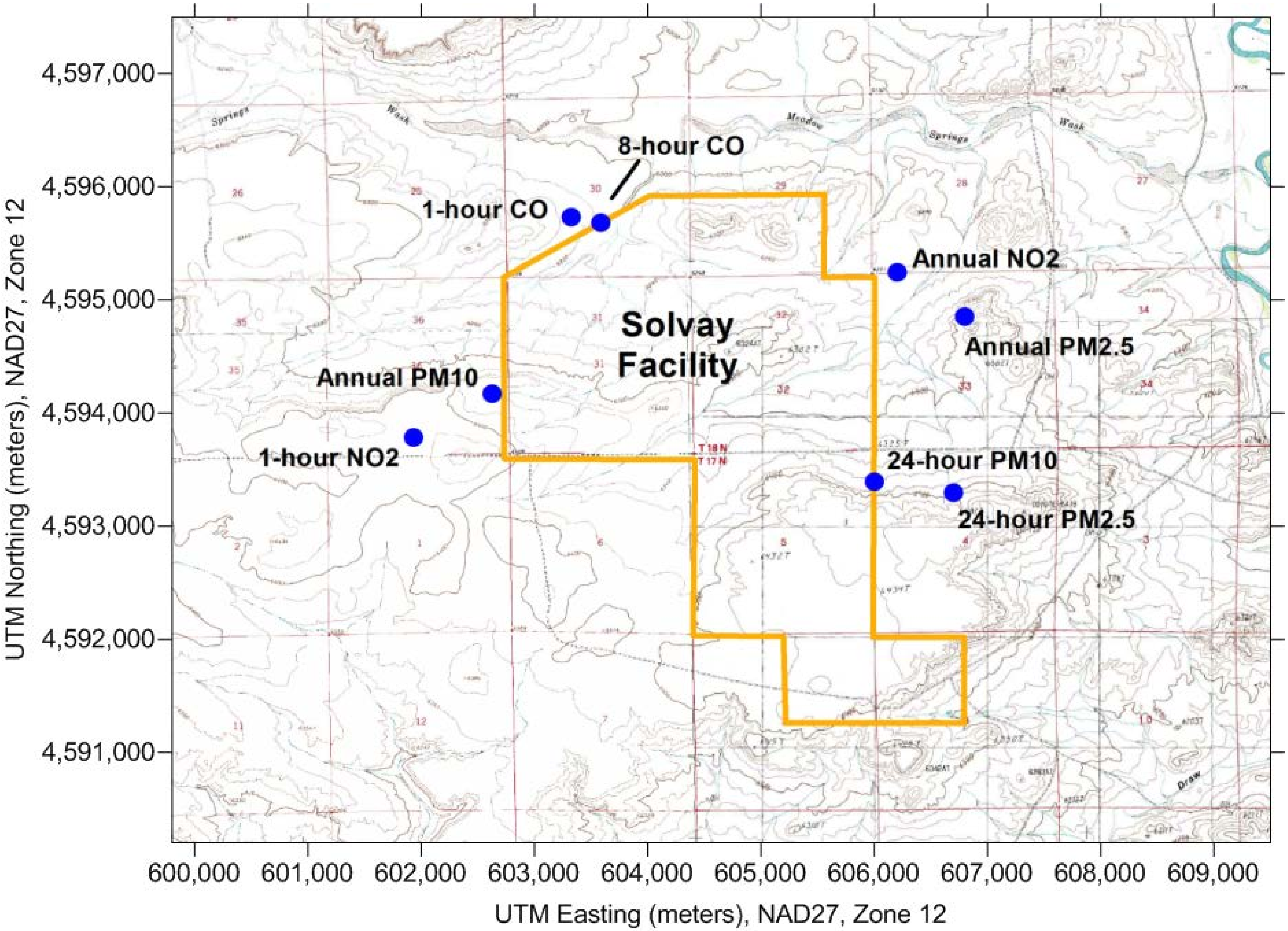


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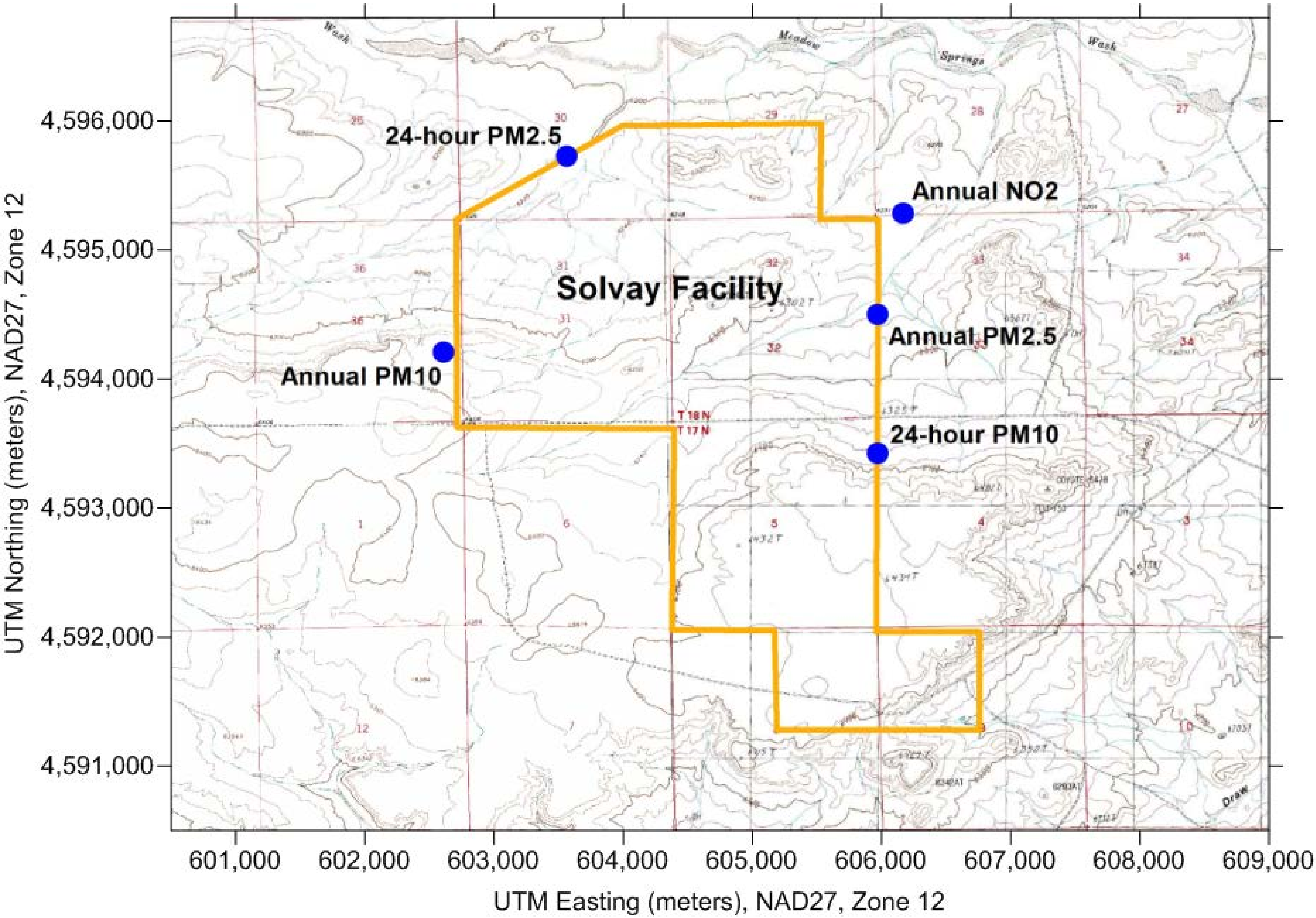
Figure 7-8. Map of Locations of Maximum Modeled Impacts from Increment Analysis



8.0 AIR QUALITY IMPACT EVALUATION – CLASS I AREAS

8.1 Class I Areas with Respect to Solvay Facility

The United States Congress established certain areas, e.g., wilderness areas and national parks (NP), as mandatory Class I areas. Procedures exist under the PSD regulations to redesignate the Class II areas to either Class I or Class III, depending upon a State's land management objectives. Although it is not one of the 156 Federal Class I areas, the State of Wyoming has declared that the Savage Run Wilderness area must be managed as a Class I area.

Figure 8-1 shows the location of the Class I areas with respect to the Solvay facility. All Class I areas are located greater than 50 kilometers (km) from the Solvay facility. Table 8-1 lists each Class I area, the managing agency (the U.S. Forest Service (USFS), under the Department of Agriculture (USDA), the National Park Service (NPS), or the State of Wyoming), and the distance from the Solvay facility to each Class I area.

Figure 8-1. Location of Class I Areas within 300 Kilometers of the Solvay Facility

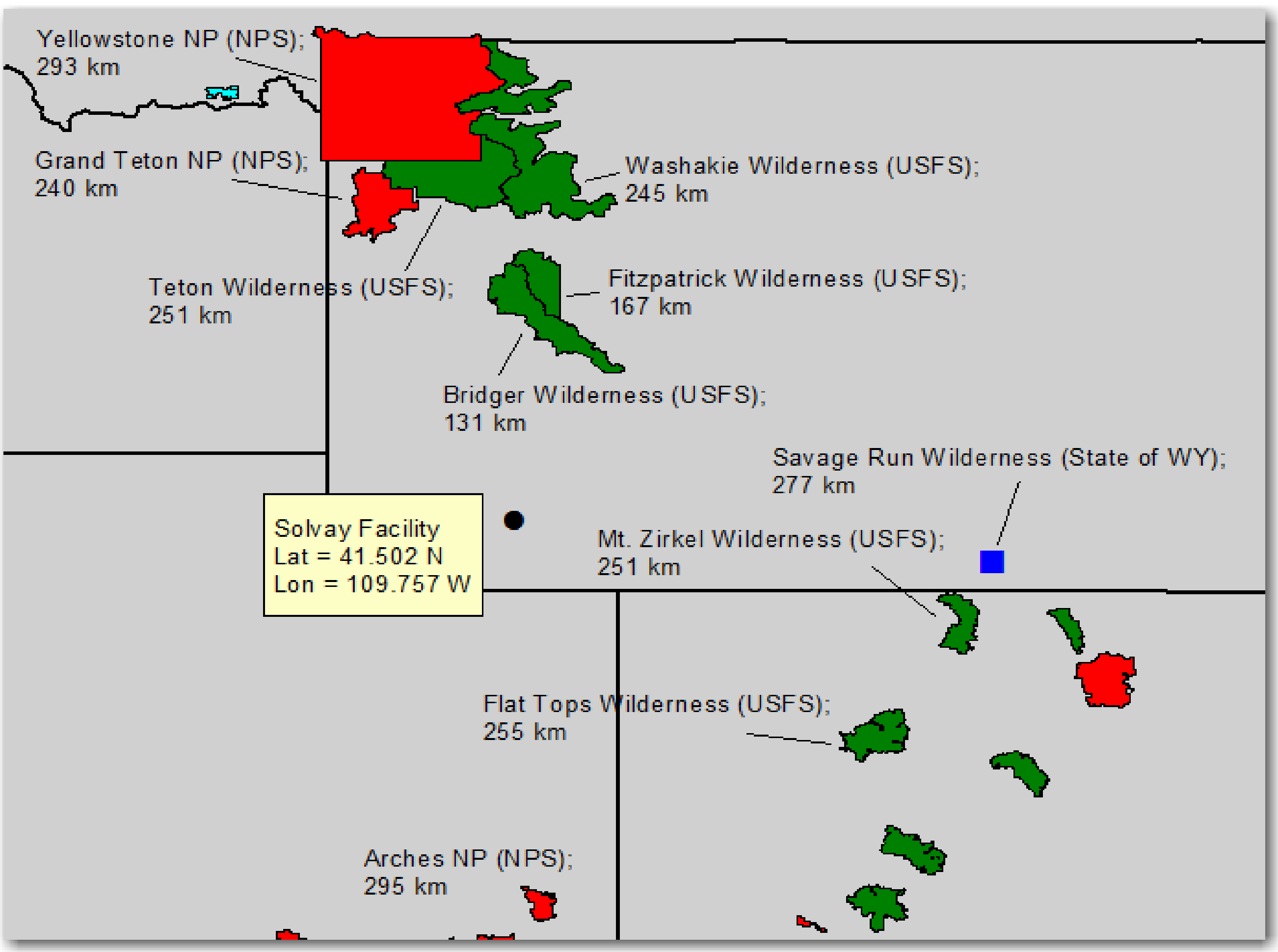


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Table 8-1. Class I Areas Located within 300 Kilometers of Solvay

Class I Area	Agency	Distance (km)
Bridger Wilderness	USFS	131
Fitzpatrick Wilderness	USFS	167
Grand Teton National Park	NPS	240
Washakie Wilderness	USFS	245
Teton Wilderness	USFS	251
Mt. Zirkel Wilderness	USFS	251
Flat Tops Wilderness	USFS	255
Savage Run Wilderness	Wyoming	277
Yellowstone National Park	NPS	293
Arches National Park	NPS	295

8.2 Class I Area Air Quality Related Values (AQRV) Analysis

Under the Clean Air Act, the Federal Land Manager (FLM) and the Federal official with direct responsibility for management of Federal Class I parks and wilderness areas (i.e., Park Superintendent, Refuge Manager, Forest Supervisor) have an affirmative responsibility to protect the air quality related values (AQRVs) (including visibility, ozone, deposition) of such lands, and to consider whether a proposed major emitting facility will have an adverse impact on such values. To address this concern, the FLMs formed the Federal Land Managers' Air Quality Related Values Work Group (FLAG). As outlined in the Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised (2010)[42], an Initial Screening Criteria analysis was established by FLAG to determine whether or not it is necessary to perform AQRV analysis at Class I areas as part of a PSD permitting process for a facility. This analysis considers the magnitude of emissions from a proposed project and the distance from the proposed project to surrounding Class I areas.

For the package boiler project, Solvay provided a technical summary of a Class I Area FLAG Initial Screening Criteria analysis (dated April 20, 2012) for the boiler project to WDEQ for FLM review prior to the submittal of an impact modeling protocol and PSD permit application to WDEQ. In the analysis, Solvay concluded that it was not necessary to evaluate AQRVs at the Class I areas surrounding the facility. On May 14, 2012, WDEQ advised Solvay that the USFS FLM concurred with Solvay's conclusions that an AQRV analysis was not necessary for the package boiler project. A copy of the Solvay's Class I Area FLAG Initial Screening Criteria analysis and correspondence with WDEQ and the USFS FLM is provided as Appendix L: . Solvay's Class I Area FLAG Initial Screening Criteria analyses did not require Solvay to perform further AQRV analyses, but it was still necessary to evaluate Class I PSD increments

[42] Natural Resource Report NPS/NRPC/NRR—2010/232; http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf1

which are not exempted from the FLAG screening analysis. A Class I PSD increment analysis for the boiler project is provided in Section 8.3.

8.3 Class I PSD Increment Analysis

Table 8-2 shows the Class I PSD increments and their associated SILs.

Table 8-2. Class I Increments and SILs

Criteria Pollutant	Averaging Time	Class I PSD Increment (µg/m³)	Class I SIL (µg/m³)
PM_{10}	24-hour	8	0.3
	Annual	4	0.2
$PM_{2.5}$	24-hour	2	0.07
	Annual	1	0.06
NO_2	Annual	2.5	0.1

In order to make a conservative concentration estimate, AERMOD was run with receptors placed at a distance of 50 km from the facility. The receptors were set at the lowest, middle level, and highest elevation for all of the Class I areas within 300 kilometers of the Solvay facility. The resultant concentrations were compared to the Class I SILs and are shown in Table 8-3. Modeling demonstrates that the emissions from the Solvay boiler project are less than the significant impact levels at the Class I areas and that a cumulative PSD increment analysis (i.e., full analysis) is not required. This Class I SIA modeling demonstrates that the project would not threaten any Class I PSD increment at any Class I area, the nearest of which is an additional 81 kilometers from the most distant receptor used in the analysis.

Table 8-3. Summary of Maximum Modeled Impacts Compared to Class I Area SILs

Criteria Pollutant	Averaging Time	Max. Modeled Impact (µg/m³)	Class I SIL (µg/m³)	Significant Impact?
PM_{10}	24-hour	0.06	0.3	No
	Annual	0.02	0.2	No
$PM_{2.5}$ *	24-hour	0.04	0.07	No
	Annual	0.01	0.06	No
NO_2	Annual	0.04	0.1	No

* Probabilistic standard; three-year average of the maximum modeled values on a receptor-by-receptor basis.

9.0 PSD ADDITIONAL IMPACTS ANALYSIS

The PSD additional impacts analysis generally has three parts: growth, soil and vegetation impacts, and visibility impairment. According to WAQSR, Chapter 6, Section 4(b)(i)(B)(I), for the PSD additional impact analyses, the owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

9.1 Growth Analysis

For the growth analysis, an estimate of the amount of possible growth is made. Because the facility is an existing facility, the growth associated with the boiler project is likely to be minor as no new work shifts will be added. The construction of the project may result in a small temporary increase in the local population during the construction period for the project, but would not result in a significant population shift or increase. Therefore, additional air quality impacts from growth as are result are not expected.

9.2 Soil and Vegetation Impacts

According to EPA in its October 1990 *Draft – New Source Review Workshop Manual*, for most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects. In addition, EPA provides a screening procedure for the impacts of air pollutant sources on plants, soils, and animals.[43] Solvay has conducted a search for information regarding soils and vegetation in the vicinity of the facility. As described further in Section 9.2.3, maximum predicted air quality impacts from Solvay are less than both the secondary NAAQS and EPA's screening thresholds for soils and vegetation and will not adversely affect these resources.

9.2.1 Soils Survey

The physiography of the area in the region of the Solvay facility is characterized by alluvial fans, piedmont plains, and pediments slopes from the surrounding mountains that form broad intermountain basins. The topography ranges from nearly level to steep. Most of the soils formed in alluvium, slope alluvium, or residuum derived from sedimentary materials. Many of the soils are shallow or moderately deep to shale or sandstone bedrock.

[43] EPA. A Screening Procedure for the Impacts of Air Pollutant Sources on Plants, Soils, and Animals. December 12, 1980. EPA 450/2-81-078. From webpage: http://cfpub.epa.gov/ols/catalog/catalog_display.cfm?&FIELD1=AUTHOR&INPUT1=Levenson%20AND%20J%20AND%20B&TYPE1=ALL&item_count=2

Baseline information used to characterize soils in the vicinity of the Solvay facility was derived from the University of Wyoming, Soils of Wyoming: A Digital Statewide Map at 1:500,000-Scale, data review and analyses (Munn and Arneson 1998)[44]. This mapping was developed using soil-landscape models and available data in the form of published soil surveys, maps, and reports of the Natural Resources Conservation Service (NRCS), the USFS, the Bureau of Land Management (BLM), and numerous theses and scientific papers published by the Wyoming Agricultural Experiment Station and the University of Wyoming.

Based on this data source, regional source soil resources in the vicinity of the Solvay facility are characterized as Soil Zone 10 (Green River Basin. Intermountain Basin. Frigid, aridic). The landscape in this extensive southwestern Wyoming basin environment is dominated by the broad exposure of Tertiary shales and sandstones, many of which are noted for their rich fossil record. Soils on the tertiary bedrock are an association of Haplocambids and Torriorthents, with Fluvents along ephemeral channels and Mollisols on favorable sites. The zone contains Psamments on stabilized sand dunes and salinized soils in playas. Sodium-affected soils (Natrargids) occur on alluvial fans on high-sodium parent materials. Uplifted areas of cretaceous and older rock add to the complexity of the area.

Soil mapping data obtained by Solvay in a Geographical Information Systems (GIS) format[45] provides soil information in the vicinity of the Solvay facility per a soil map unit (SMU) classification system.[46] Within a 10 kilometer by 10 kilometer area surrounding the Solvay facility, the dominant SMU are WY44 (83%), WY10 (16%), and WY17 and WY40 (<1%). Descriptions of these SMU have been provided in environmental assessments (EA) for other facilities in Sweetwater County and are provided below.[47]

The majority of soils (83 percent) located within 10 kilometers of the Solvay facility are Haplargids and Torrifluvents (soil map unit WY44). These categories are fine-loamy over sandy or sandy-skeletal, mixed, mesic. These soils occur on alluvium and slopes of Pleistocene and Holocene age over a variety of bedrocks.

Approximately 16 percent of the soils within 10 kilometers of the Solvay facility are Typic Torripsamments (soil map unit WY10). In this intermountain basin environment, Typic Torripsamments occur on stabilized dunes intermingled with active dune lands. Thin topsoil horizons are evident at the dune surface; however, soil development in these soils is poor. These soils have developed in eolian parent materials. These soils include strongly alkaline fine sand to coarse loamy soils about 60 inches deep, and are excessively drained. These soils occur as nearly level to undulating alluvial bottomlands and fans with scattered dune lands. Where these soils are undisturbed the sand is stabilized by

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44 From webpage: http://www.wyomingextension.org/agpubs/pubs/b1069.pdf

45 From Wyoming GeoLibrary webpage: http://wygl.wygisc.org/wygeolib/catalog/main/home.page

46 From webpage: http://www.wyomingextension.org/agpubs/pubs/b1069.pdf

47 From webpage: http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/rsfodocs/tablerock.Par.62462.File.dat/TableRockFinalEA.pdf

vege d or unstabilized dune communities, the hazard for wind erosion is severe.

Less than one percent of the soils within 10 kilometers of the Solvay facility are comprised of Rock Outcrop and loamy-skeletal, Typic Torriorthents (soil map unit WY17). These poorly developed stony soils occupy ridge crests intermixed with areas of rock outcrop. These soils range in depth from very shallow to moderately deep. The soils tend to be much coarser than the soils on the adjacent lower slopes, and contain hard clasts of local bedrock. The adjacent lower slopes generally developed from shale residuum, which weathers to fine textured clays, and slope alluvium. These clays result in poor infiltration, high runoff, and high potential for slumping. Sensitive soils are found on steeper slopes (greater than 25 percent) and areas of exposed bedrock, often associated with badlands.

Less than one percent of the soils within 10 kilometers of the Solvay facility are characterized as soil map unit WY40 described in the subsequent text. Ustic Haplocambids are moderately to weakly developed and occur on gentle to steep slopes. Coarse-loamy, Ustic Torriorthents have soil textures that generally range from silt loams to sandy loams. Loamy-skeletal, Typic Torrifluvents have 35 percent or more rock fragments and textures range from sands to sandy clay loams. This portion of the project area also has shallow and moderately deep Haplocambids and poorly developed Torriorthents occurring on slopes along ephemeral channels. Torrifluvents formed in alluvial deposits along larger gully and drainage bottoms and are very deep. Bottomland soils have developed primarily in alluvial deposits. These bottomland soils can be saline or sodic in relation to the parent material they are derived from.

9.2.2 Vegetation Survey

According to WAQSR, Chapter 6, Section 4(b)(i)(B)(I), for the PSD additional impact analyses, the owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

The Solvay facility is located in the Wyoming Basin ecoregion.[48] The land use surrounding the Solvay facility is predominantly shrubland with very small areas of bare rock/sand clay and grasslands.[49] Shrublands are areas characterized by natural or semi-natural woody vegetation with aerial stems, generally less than 6 meters tall, with individuals or clumps not touching to interlocking. In this region, the chief vegetation is made up of sagebrush (*Artemisia tridentata*) mixed with short grasses (various *Agropyron* species or fescue grass).

Most of the Wyoming Basin is sagebrush steppe; actually a shrubland mosaic dominated by Wyoming big sagebrush. In places of shallow soil and on windswept ridges, Wyoming big sagebrush may be replaced by black sagebrush or communities of cushion plants. Gardner saltbush and greasewood are especially common on alkaline soils and basin big sagebrush or silver sagebrush may thrive in more

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[48] From LandScope America webpage: http://www.landscope.org/explore/natural_geographies/ecoregions/Wyoming%20Basins/

[49] From National Land Cover Database (NLCD) webpage: http://www.mrlc.gov/index.php

moist locations.[50] Moist alkaline flats support alkali-tolerant greasewood.[51] With the exception of the few riparian areas, much of the sagebrush steppe is devoid of trees.

Solvay has performed a preliminary survey of any potential vegetation with commercial or recreation value in the vicinity of the facility using aerial photographs available from Google Earth. From the Google Earth survey, there is no vegetation in the immediate vicinity of the facility (i.e., and hence maximum modeled impact locations) which would have significant commercial or recreational value.

However, Solvay has identified some isolated areas of cultivated land (assume hay farming) with potential commercial value located approximately 6 and 8 kilometers to the southeast of the facility adjacent to Blacks Fork of the Green River (a tributary of the Green River).

9.2.3 Modeled Impacts to Soils and Vegetation

As provided in Section 7.7.2 the maximum impacts from the boiler project result in impacts below secondary NAAQS standards which provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. In addition, modeled impacts of several criteria pollutants are compared to concentrations at which adverse growth or tissue injury has been reported in the literature for exposed vegetation.[52] Predicted concentrations for the project area were well below the thresholds for damage, as shown in Table 9-1.

Table 9-1. Comparison of Predicted Project Impacts to Vegetation Damage Threshold

Pollutant	Averaging Period	Threshold Concentration For Sensitive Vegetation (μg/m³)	Solvay Facility Max. Modeled Impact (μg/m³) *	Modeling Averaging Period Used
Nitrogen Dioxide (NO_2)	4-hour	3,760	160.1	1-hour
	8-hour	3,760	160.1	1-hour
	Month	564	14.3	1-year
	Annual	94	14.3	1-year
Carbon Monoxide (CO)	1-week	1,800,000	1,709	8-hour

* Reported impacts for all pollutants represent the maximum result from the full-impact modeling (Solvay facility + competing sources).

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[50] From LandScope America webpage: http://www.landscope.org/explore/natural_geographies/ecoregions/Wyoming%20Basins/

[51] From the USGS Description of the Ecoregions of the United States webpage: http://www.fs.fed.us/colormap/ecoreg1_provinces.conf?228,200

[52] EPA. "A Screening Procedure for the Impacts of Air Pollutant Sources on Plants, Soils, and Animals." December 12, 1980. EPA 450/2-81-078. From webpage: http://cfpub.epa.gov/ols/catalog/catalog_display.cfm?&FIELD1=AUTHOR&INPUT1=Levenson%20AND%20J%20AND%20B&TYPE1=ALL&item_count=2.

9.3 Visibility Impairment Analysis

The Solvay project area does not include any protected Class II views that have been identified by WDEQ. For visibility impairment analysis for all other Class II areas, a comparison to the secondary ambient standards (WAAQS/NAAQS) is made as the secondary standards are intended to protect these resources. As shown in Section 7.7.2 maximum modeled impacts from the project are less than the secondary ambient standards and the project will not adversely impair visibility at Class II areas.

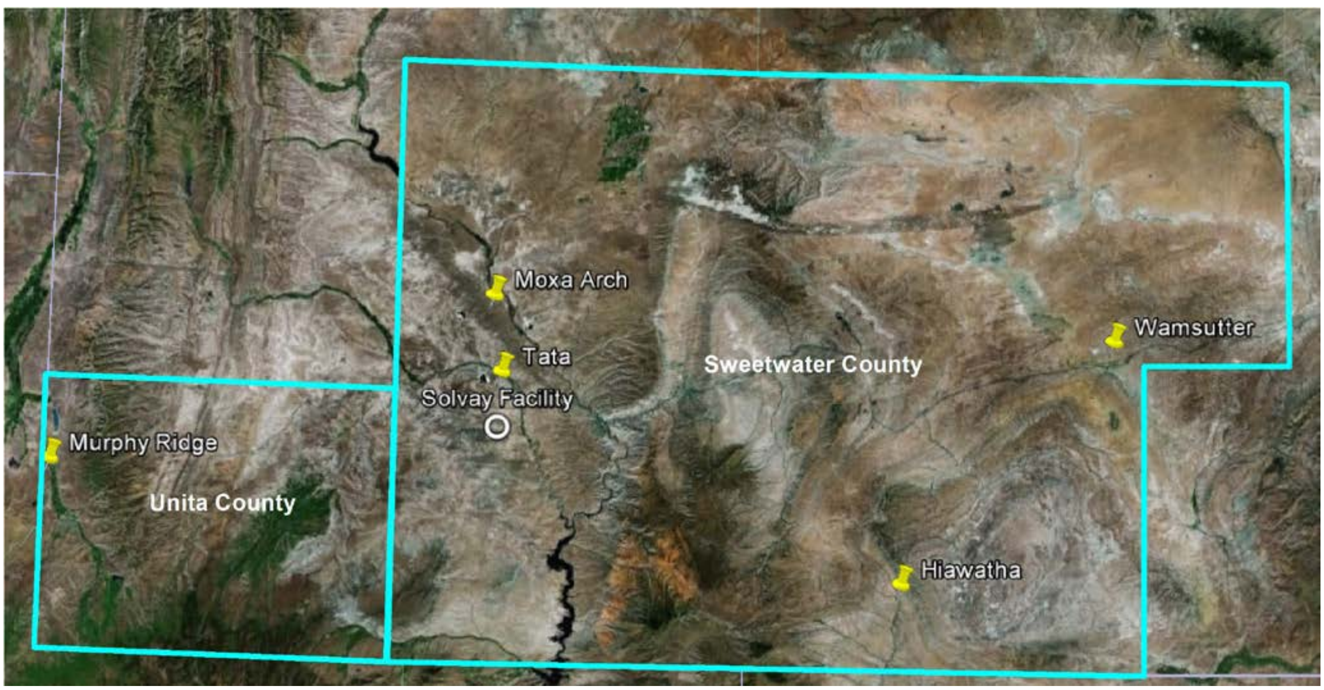
In regard to Class I area visibility protection, as described in Section 8.2, the USFS FLM has concurred with Solvay analysis that an AQRV analysis was not necessary for the package boiler project based on projected emissions for the project and distances from the Solvay facility to surrounding Class I areas.

10.0 OZONE ASSESSMENT

Because the proposed project's ozone (O_3) precursor emissions (NOx and VOC) exceed their SERs, WDEQ has asked that Solvay provide a qualitative discussion on ozone impacts since there is no SIL for ozone. For this analysis, ozone impacts are analyzed qualitatively by comparing the Solvay project's ozone precursor emissions (NO_X and VOC emissions) to countywide ozone precursor emissions in conjunction with existing ozone monitoring data. As described in this section, Solvay's project contribution to ozone formation is not expected to be significant and the project is not expected to cause or contribute to an exceedance of the ambient standards for ozone.

The Solvay facility is located in Sweetwater County, Wyoming. Solvay has identified four ozone monitoring stations in Sweetwater County as shown in Figure 10-1. In addition, the upwind ozone monitoring station at Murphy Ridge in Unita County to the west of the Solvay facility is shown.

Figure 10-1. Ozone Monitoring Stations in Sweetwater and Unita Counties



As shown in Table 10-1. Maximum Measured Ozone Concentrations in Sweetwater and Unita Counties, the measured ozone concentrations at these monitoring stations are all below the ozone WAAQS/NAAQS.

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Table 10-1. Maximum Measured Ozone Concentrations in Sweetwater and Unita Counties

Monitor	County	Monitored Concentration (ppb) [2] 2009	2010	2011	Average	NAAQS/ WAAQS (ppb) [3]	Percentage of NAAQS/ WAAQS
Moxa Arch	Sweetwater	---	66	68	67.0	75	89%
Hiawatha	Sweetwater	---	---	63	63.0	75	84%
Tata	Sweetwater	---	---	56	56.0	75	75%
Wamsutter	Sweetwater	62	67	64	64.3	75	86%
Murphy Ridge	Unita	60.2	65	65	63.4	75	85%

1 Sources:

EPA AirData Database: http://www.epa.gov/airdata

Wyoming Visibility Monitoring Network: http://www.wyvisnet.com/index.aspx

2 Concentrations shown are the H4H daily 8-hour maximum concentration for each year reported.

3 8-hour ozone NAAQS/WAAQS is based on the three-year average of the H4H daily 8-hour maximum concentration.

The latest data from the Western Regional Air Partnership (WRAP) Emissions Data Management System (EDMS)[53] indicates Sweetwater County emissions in 2002 (latest year of data available) from all sources (mobile, non-mobile, point, etc.) of NO_x and VOC (i.e., ozone precursors), were approximately 62,000 tons/year and 104,000 tons/year, respectively. Table 10-2 provides a comparison of Solvay's boiler project ozone precursor emissions to existing Sweetwater County ozone precursor emissions. As shown in Table 10-2, the expected emissions from the project represent a very small fraction of countywide emissions. Existing Sweetwater County NO_x and VOC emissions represent approximately 443 times more NO_x and 233 times more VOC than those from the proposed boiler project.

Given these factors, the Solvay's boiler project emissions contribution to ozone formation is not expected to be significant and the project should not cause or contribute to an exceedance of the ambient standards for ozone.

53 Western Regional Air Partnership (WRAP) Emissions Data Monitoring System (EDMS) Database. *Emissions Inventory Reports (EDMS).* 2002 Version 3 (Base02b). http://vista.cira.colostate.edu/tss/edms.aspx

Table 10-2. Ozone Precursor Emissions: Solvay Project vs. Sweetwater County

Category	Emissions (tpy) NOx	Emissions (tpy) VOC
Net Emissions Increase from Solvay Boiler Project	140.0	447.8
Sweetwater County Total [1]	61,993	104,273
Project Percentage of Sweetwater County Total	0.2%	0.4%

[1] Source: WRAP EDMS, 2002 Version 3 (Base02b)
http://vista.cira.colostate.edu/tss/edms.aspx

11.0 INHALATION RISK ASSESSMENT

A screening risk assessment addressing the impacts HAP emissions from the project (new boiler and debottlenecked combustion sources) is provided in this section.

The inhalation risk assessment for hazardous air pollutants was conducted using a Tier 1 (screening level) approach to estimate the chronic carcinogenic risks for the project. The analysis followed the facility-specific assessment guidance developed by the EPA as described in the document Air Toxics Risk Assessment Reference Library, Volume 2, Facility-Specific Assessment, using the AERMOD model. The Tier 1 analysis provides a conservative single estimate of maximum ambient air concentration used to estimate the chronic cancer inhalation risk based on an assumption that the maximum-exposed individual could reside at the offsite location of maximum concentration (and theoretically be exposed to impacts 24 hours per day over a period of a full lifetime), whether or not a person actually lived there.

The Inhalation Unit Risk (IUR) from EPA's HAPs Summary[54] was used as the screening levels for chronic carcinogenic risk (dose response values) and is provided on Appendix M: , Page 1. The IUR is defined as the upper-bound excess lifetime cancer risk estimated to result from continuous exposure to an agent via inhalation per 1 $\mu g/m^3$ over a lifetime. The interpretation of unit risk is as follows: if the IUR = 1.5 × 10-6 per $\mu g/m^3$, then not more than 1.5 excess tumors may be expected to develop per 1,000,000 people if exposed continuously for a lifetime to 1 $\mu g/m^3$ of the chemical inhaled. The number of expected tumors may be less; it may even be none.

The estimated excess lifetime cancer risk (R) is found by multiplying the lifetime average concentration (EC) and IUR for each HAP. The cumulative risk is the sum of the individual risk values. If the combined risk is less and one-in-a-million, then the risk is assumed insignificant and the analysis is complete. The excess lifetime cancer risk was calculated using the following equation:

Risk = EC x IUR

where,

Risk = excess lifetime cancer risk estimate (unitless),
EC = modeled exposure concentration based on a lifetime of continuous inhalation exposure to an individual HAP ($\mu g/m^3$),
IUR = dose response value, i.e., the inhalation risk estimate for that HAP [$1/(\mu g/m^3)$].

54 http://www.epa.gov/ttn/atw/toxsource/summary.html

As discussed in the modeling protocol, only emissions from the project (gas-package boiler and debottlenecked combustion sources) were considered and emissions from these sources are provided in Appendix M: . Emission factors for the carcinogenic HAPs from the gas-package boiler and debottlenecked combustion sources were obtained from AP-42, Section 1.1 for coal combustion (#17) and AP-42, Section 1.4 for gas combustion (package boiler, #48, #51, #80, #82).

To focus the analysis on the most significant HAPs, Solvay applied the toxicity-weighted screening analysis (TWSA), as described in the EPA document Air Toxics Risk Assessment Reference Library, Volume 2, Facility-Specific Assessment. Page 3 of Appendix M: provides the entire TWS analysis and Table 11-1 presents a summary of the TWSA, which uses the product of the expected emissions for a given HAP and the dose response value for that HAP. The products calculated in this way were ranked from highest to lowest, and the HAPs within the 99th cumulative percentile were selected to carry forward to the inhalation risk modeling.

Table 11-1. Toxicity-Weighted Screening for Carcinogenic HAPs

Pollutant	Ref.	X = Total Emissions (tpy)	Y = Dose Response Risk Factor ($1/\mu g/m^3$) **	X * Y	Percent of Total (X * Y)	Cumulative (%)
Arsenic	ARS	3.70E-02	0.0043	1.59E-04	56.5%	56.5%
Chromium (VI)	CVI	6.92E-03	0.012	8.30E-05	29.5%	86.0%
Cadmium	CAD	1.04E-02	0.0018	1.87E-05	6.6%	92.6%
7,12-Dimethylbenz(a)anthracene	DIM	8.62E-05	0.071	6.12E-06	2.2%	94.8%
Formaldehyde	FRM	4.25E-01	0.000013	5.52E-06	2.0%	96.8%
Beryllium	BER	1.90E-03	0.0024	4.57E-06	1.6%	98.4%

For the model runs that were used to determine the long-term average impacts from the six modeled carcinogenic HAPs, Solvay modeled three years of annual impacts. For each of these HAPs, Solvay determined the average of these three years of concentrations to determine a long-term average on a receptor-by-receptor basis. Then the risk contributions (Risk = EC x IUR) from each HAP were summed to determine a total risk value on a receptor-by-receptor basis. Because AERMOD only generates modeled output to five decimal places, and not in scientific notation, the emission rates used in the modeling analysis were the actual rates calculated in Appendix M: multiplied by 1000. Then, the resulting impacts were divided by 1000 so that very small impacts could be accounted for numerically.

The overall highest predicted increased cancer risk was very low at 0.36 per million at a receptor on the eastern ambient boundary of the facility (UTM Easting = 606,000.0 meters, UTM Northing = 4,594,450.8 meters). Table 11-2 presents a summary of the results of the risk analysis.

Table 11-2. Carcinogenic Inhalation Risk Summary at Maximum Impact Receptor

Pollutant	Ref.	Modeled Result, EC [1] (μg/m³)	Dose Response Risk Factor, IUR (1/μg/m³) **	Calculated Risk EC * IUR
Arsenic	ARS	4.15E-05	0.0043	1.8E-07
Chromium (VI)	CVI	7.27E-06	0.012	8.7E-08
Cadmium	CAD	2.56E-05	0.0018	4.6E-08
7,12-Dimethylbenz(a)anthracene	DIM	3.03E-07	0.071	2.2E-08
Formaldehyde	FRM	1.44E-03	0.000013	1.9E-08
Beryllium	BER	2.16E-06	0.0024	5.2E-09
		Total Increased Cancer Risk (per million) >		**0.36**

[1] At maximum modeled receptor.

Appendix A: Foster Wheeler Boiler Specifications

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Operating and Design Conditions	
Minimum Boiler Design Parameters	
Steam Flow -Capacity, lb/hr, each	200,000 lb/hr
-Temperature, °F	435
-Pressure, psig	350
Blowdown	6450 lb/hr ⚠1
Automatic Turndown Required	25% ⚠1
Return Condensate -Flow, lb/hr ⚠1	200,000
-Temperature, °F	199
Makeup Water -Flow, lb/h	6450 ⚠1
-Temperature, °F	199 ⚠1
-Pressure, psig	25
-Analysis	
-Total dissolved solids	Negligible ⚠1
-Hardness	0 ⚠1
-Conductivity	
-Silica	Negligible ⚠1
-Free or combined CO_2	
Stack Emissions Design Parameters	
-Maximum allowable NO_x	0.035 Lbs / MMBTU (HHV) ⚠2
-Maximum allowable CO	100 ppm

Note to the Bidder:
Bidder is requested to confirm the data filled in the right hand column and fill in any blank lines as completely as possible. Please type or print and stay within the lined area.

(The information provided in these data pages (1-5) is to be considered preliminary and subject to final contract review)

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**		
Operating and Design Conditions (cont'd.)			
Equipment Location	Indoors at Elev. 6600 FASL		
Duty	Continuous		
Natural Gas (At various heating values supplied)	Lowest	Highest	Intermediate
Gross-Heating value, BTU/scf		1064.1	
-Net heating value, BTU/scf		961.0	
(dry basis @ 14.73 psia & 60 °F)			
-Specific gravity (dry basis)		0.61	
-Composition, Volume %			
-Carbon dioxide		2.47	
-Nitrogen		0.61	
-Methane		90.45	
-Ethane		4.07	
-Propane		1.39	
-Iso Butane		0.24	
-Normal Butane		0.27	
-Iso Pentane		0.13	
-Normal Pentane		0.10	
-Hexane		0.24	
-Helium		0.03	
-Sulfur (gr./100 scf)			

Note to the Bidder:
Bidder is requested to confirm the data filled in the right hand column and fill in any blank lines as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001/ 002**	
Number-required/operating/standby	2/2/0	
Vendor	Foster Wheeler ⚠1	
Manufacturer	Foster Wheeler ⚠1	
Model No.	AG-5195 ⚠1	
Manufacturer Location	St. Catharines, Ontario ⚠1	
Heat Input (Max), MMBTU/hr ⚠2	250 ⚠1	
System Performance	100% condensate	100% make up
Hot Water Flow -Capacity, lbs./hr.	215,000 ⚠1	215,000 ⚠1
-Temperature, °F	240 ⚠1	240 ⚠1
-Pressure, psig	395 ⚠1	395 ⚠1
Turndown Capacity	10:1	
Efficiency (Predicted) ⚠2	83.2921 ⚠2	
Utility requirements		
-Electrical, kW/V-ph-Hz		
-Plant air, scfm @ psig		
-Instrument air, scfm @ psig		
-Low pressure steam, lb/hr @ psig		
-Cooling water, gpm @ °F		
-Natural gas, lb/hr @ psig ⚠2	11,384 (based on 0% blowdown) ⚠2	
-Natural gas, mm BTU/hr.,	249.8 ⚠2	
Flue gas		
-Volume, acfm	80,115 ⚠1	
-Temperature, °F	320 ⚠1	
-Composition:		
O_2, %	2.827 ⚠1	
Co_2, %	13.591 ⚠1	
H_2O, %	11.581 ⚠1	
N_2, %	72.000 ⚠1	

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Boiler	Equipment No.: 81-BO-001 / 002
-Type	"D" Type Model AG-5195
-Steam drum size	54" ID, 39' Length
-Mud drum size	24" ID, 39' Length
-Material of water tubes	SA-178
-Diameter of tubes/wall thickness	2½" / 0.135" and 2" / 0.105" △2
-Overall dimensions, ft.-in.	LxWxH – 48' x 13'-4" x 17'-9"
-Wt of boiler, lbs	180,000
-Total effective heating surface, ft^2 △2	16,490 △2
-Furnace volume, cu ft	3375 △1
Boiler Burner	
-Manufacturer/Model	Coen Company / DAF △3
-No. of Burners/Capacity per burner	1 x 208,500 lb/hr
-Description	
Boiler Combustion Air Fan	Equipment No.: 81-FN-031 / 032
-Manufacturer	Howden Fans △1
-Model	1085BA97 △1
-Capacity, acfm @ in. H_2O	88,141 @ 27.68" WC
-Material casing and wheel	
-Motor hp	600 △2
Economizer	Equipment No.: 81-HR-001 / 002
-Water capacity, lbs/hr	208,500
-Water inlet temperature, °F	240
-Water outlet temperature, °F	339
-Pressure drop, psi	6
-Effective heating surface, ft^2	16,484 △1

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Deaerator	Equipment No.: 81-DE-001/002
-Manufacturer/Model No.	Kansas City Deaerator △1
-Size of Tank	8'-6" Diameter, 21' Length
-Materials/thickness, in.	0.25
-Operating conditions -Pressure, psig	10
-Temperature, °F	240
-Design conditions -Pressure, psig	30
-Temperature, °F	410
-Residual O_2 in effluent, mg/l	0.005
-Steam flow, Lb/h	17,000
Boiler Feedwater Pumps	Equipment Nos.: 81-PP-098A thru C
-Manufacturer/Model No.	Carver / WKM-80 △1
-Capacity and pressure, gpm @ psig	245,000 lb/hr @ 500 psi △3
-Materials of Construction	D.I. / C.I. △1
-Motor hp	250
Boiler Stack	One stack per boiler
-Diameter & Height, feet △2	5'-9 3/4" Diameter, 50-ft overall
-Materials of Construction	Carbon Steel
-Nozzles Provided	Two (2) 4" flanged sampling ports
Chemical Injection Package	Equipment No.: 81-WT-007/008/009/010
-Manufacturer/Model No.	Neptune △1
-Size of Tank	200 gallons each
-Materials/thickness, in.	316SS △1
-Chemicals Used	Sulfite, Phosphate
-Pump Capacity & Pressure	12 gal/hr △3

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

Appendix B: Coen Burner Bid

From: **Wieszczyk, Wayne** <wwieszczyk@coen.com>
Date: Fri, May 4, 2012 at 11:34 AM
Subject: RE: Solvay project: Further questions regarding 9ppm burner; Coen #201202-24271-A
To: "Schmidt, Ryan" <ryan.schmidt@solvay.com>
Cc: North Associates <northassociates@yahoo.com>, "Ingvarson, Lyall" <lyall.ingvarson@coen.com>

Ryan,

Coen is pleased to offer the following information per your request.

1) Coen can offer 50 PPM CO along with the 9 PPM NOx at 100% MCR with 30% FGR and 15% EA. The CO will be guaranteed from 25-100% MCR. The only condition we would be concerned with is that the boiler furnace wall should be seal-welded to help assure no CO bypassing. If the wall is not sealed, Coen would recommend a CO test port at the rear of the furnace to allow us to confirm the CO at the rear vs. the stack during start-up if this became an issue.

2) The products of combustion are listed below based on 100% MCR (253.77 mmbtu/hr) and 30% FGR and 15$% excess air.

Combustion Products

	vol%, wet	vol%, dry	scfm	mass%, wet	mass%, dry	lb/hr	MW
CO2	8.53%	10.19%	4352	13.43%	15.01%	29755	44.0
H2O	16.36%		8351	10.55%		23374	18.0
O2	2.51%	**3.00%**	1279	2.87%	3.21%	6359	32.0
N2	71.75%	85.79%	36622	71.93%	80.41%	159378	28.0
Ar	0.86%	1.02%	437	1.22%	1.37%	2713	39.9
SO2	0.00%	0.00%	0	0.00%	0.00%	0	44.0

1) The following estimated temperate per your request for NG

ADFT of NG = 3,391 deg F

Flue Gas Temperature downstream of the economizer = 350 deg F

Flue Gas Temperature in the stack = ~350 deg F

If you need any further information, please feel free to contact us anytime.

Regards,

Wayne A. Wieszczyk

Sr. Application Engineer

Boiler Burner Group

Coen Company Inc.

2151 River Plaza Dr, Suite 200

Sacramento, CA 95833

Coen® Ultra Low NOx Burner Package to meet 9 PPM (Coen File D-13384-1-000)

SUBMITTED TO

Mr. Mike Ganskop
Solvay Chemicals

FOR

Solvay Chemicals
Green River, Wyoming

Proposal Number:	201202-24271-A R1
Application Engineer:	Wayne A. Wieszczyk
Tel:	1 (530) 668-2128
Email:	wayne.wieszczyk@coen.com
Date Prepared:	March 30, 2012

PROPOSAL CONTENTS

1.0 Overview

Rev. 1 Revise proposal for Ultra Low NOx burner option to meet 9 PPM NOx.

Solvay Chemicals has requested Coen® to supply option for changing the existing low NOx DAF™ burner to Ultra Low NOx burner. Coen has over 400 ULN burner installations using the RMB™ family of burners to meet single digit NOx. The RMB™ will require 30% FGR to achieve 9 PPM. Coen is offering a budget price including a new FD fan package, the new trains along with Fyr-Monitor™ BMS/CCS PLC based systems to assure the controls match the performance desired for Ultra Low NOx operation.

2.0 Burner Design Basis & Specifications

2.1 Boiler Information

Number of boilers	1
Number of burners per boiler	1
Boiler manufacturer	Foster Wheeler
Boiler designation	AG-5195
Furnace dimensions: Width inside (feet)	7.08'
Height (feet)	13.71'
Length (feet)	36.75'
Length for flame (feet)	31.75'
Steam capacity (lb/hr)	208,562
Design boiler HHV BTU input (mmbtu/hr) NG	253.77
Boiler furnace pressure at proposed conditions ("w.c.)	18.51
Steam pressure (psig)	350
Steam temperature (°F)	SAT
Boiler Feedwater temperature (°F)	236
Boiler efficiency Natural Gas	---
Maximum boiler stack height (feet)	35-40
Location	Indoor
Economizer used	Yes

2.2 Electrical & Utilities

Fan electrical characteristics (v/hz/ph)	480/60/3
Panel electrical characteristics (v/hz/ph)	120/60/1
Instrument air supply (clean, dry, and oil-free)	100 psig

2.3 Codes

Area classification	Non-Hazardous
NEMA class rating	NEMA 4
Code requirements	NFPA 85
Piping requirements	Coen Standard
Insurance requirements	None

2.4 Combustion Air

Combustion air temperature (°F)	80
Air humidity (%)	50
Air density at standard conditions (lbm/ft^3)	0.075
Mix density with FGR/Combustion air (lbm/ft^3)	0.0512
Mix Temperature FGR/combustion air	145
Plant elevation (FASL)	6.250
Combustion air pre-heat	No

2.5 Fuels

Main gas fuel .... NG
Ignition fuel .... Natural Gas

NG Gas Details:
Higher heating value (btu/scf) 1,064
Specific gravity 0.61

2.6 Burner Performance

Burner pressure drop ("w.c.) 10.0
Burner excess air 15
FGR percent 30
Boiler turndown based on steam output: 6:1
NG regulated supply pressure required at train inlet (psig) 40
N.Gas Pilot gas pressure required (psig) 1.0

2.7 Burner Estimated Emissions

Fuel: NG
NOx (ppm, ref 3% O2) 9
CO (ppm, ref 3% O2) 123

Notes:

1. Emission guarantees are from 25-100% MCR for NG.
2. Emission guarantees based on HHV.
3. Coen will guarantee the stack CO emission to be less than 123 PPM provided furnace leakage does not contribute any CO to the total CO emissions. This guarantee is based on; 1) operating with 15% excess air at high fire; 2) 31.75 ft (min) furnace length to the superheater; 3) the boiler meeting the minimum construction requirements for furnace side wall construction and seals at the front wall and drum and 4) the customer providing sampling port for measuring the CO emissions.

2.8 Paint and Finish

Coen surface preparation and painting will be as follows:

Product

- Acrylic Emulsion primer/finish, no topcoat
- Sherwin-Williams DTM Acrylic or equivalent
- SW data sheet 1.21

Surface Preparation

- SSPC-SP6

Dry Film Thickness (S-W, other mfg see product sheet)

- 5.0 - 6.0 mils

Performance

- Consult the manufacturer's product information sheet

Technique

- Consult the manufacturer's application bulletin and JZ 9001-OPS-MFG-58

Inspection

- Consult JZ 9001-OPS-QC-61

3.0 Scope of Supply

3.1 Burner Equipment

The following is included as part of Coen's offering:

Windbox, Damper (Qty: 1)

The windbox houses the burner and is constructed of carbon steel and has insulation to reduce the surface temperature due to the FGR and combustion air mixture. The windbox is to be seal welded to the boiler front plate and is of sufficient size to provide air cooling to a major portion of the boiler front plate.

A jackshaft control drive system is mounted on the windbox front and includes:

- Purge and low fire position switches
- Ball bearing pillow blocks, self aligning, and permanently lubricated
- Mechanical linkage constructed from 1/2" pipe with heavy duty, aircraft type ends to eliminate backlash.
- Jackshaft, 1-3/16 solid round stock

The jackshaft must be driven by an actuator and will be linked to the following components:

- Windbox damper

A combustion air damper is mounted on windbox. The damper is a slow opening, multibladed, streamline design. It is designed to have a relatively straight line characteristic in respect to air flow versus damper positions. The maximum air leakage will not exceed 10% in the closed position.

Jackshaft Actuator (Qty: 1)

The jackshaft actuator is mounted on the windbox and is electrically driven. The actuator with smart positioner accepts a 4-20 mA control input signal and drives all items linked to jackshaft.

FD Fan-FGR Package (Qty: 1)

Coen will be supplying a new FD fan package to deliver the combustion air and Induce 30% FGR to the new RMB Ultra Low NOx burner. The following is included:

- FD Fan package with 800 HP TEFC motor 4160 V/3PH/60HZ, IVC damper with actuator with smart I/P positioner. Note fan will be shipped partial-assembled.
- FGR inlet box with manual damper.
- 38"D FGR x 12"D connection as part of the FGR inlet box.
- Inlet silencer with piezometer with loose DP transmitter & integral manifold valve (field installed).
- FGR damper, 38"D with actuator and I/P positioner and position feedback – shipped loose.
- FGR thermal mass flow meter with 4-20 mA output – shipped loose

RMB Burner (Qty: 1)

The RMB includes the following sub-assemblies:

- One (1) primary (inner) register with integral gas injectors and air flow swirl vanes
- One (1) secondary (outer) register with integral gas injectors and air flow vanes
- One (1) set of pre-cast refractory quarl segments that comprise of the inner zone throat.
- Two (2) manual gas butterfly valves
- Two (2) gas pressure gauges c/w isolation cocks
- One (1) burner front hub assembly, complete with two observation ports and flame scanner swivel mounts
- One (1) burner guide ring for the purpose of centering the burner in the windbox

Natural Gas Pilot (Qty: 1)

The pilot is electrically ignited and is interruptible per NFPA Class III requirements. The pilot electrode is sparked by a 6000 Volt transformer.

Natural Gas Pilot Train (Qty: 1)

Pilot train, fully assembled and mounted and wired to a junction box on the windbox with the following components:

- One inlet manual shutoff valve, bronze body.
- One strainer, 100 mesh, cast iron body.
- One pressure regulating valve, aluminum body.
- Two safety shutoff valves aluminum body.
- Two safety shutoff valve leak test valves.
- One vent valve, aluminum body.
- One manual shutoff valve, bronze body.
- One pressure gage, 4-1/2”.
- One flex hose, stainless steel.

Natural Gas Train (Qty: 1)

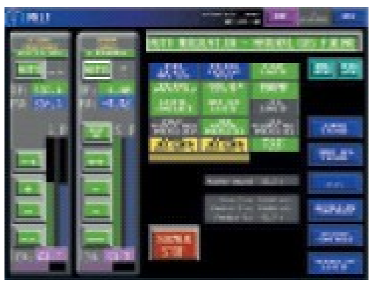
The main gas train is assembled and mounted on the windbox. Portion (*) of the train will be assembled and shipped loose for field installation, support, wiring, etc. The following components are included:

- *One manual shutoff valve, cast iron body, Homestead.
- *One strainer, cast iron body.
- *One pressure regulating valve, cast iron body, Fisher.
- *One supply pressure gauge, 4-1/2" Ashcroft.
- *One flow meter with 4-20mA output signal
- One low pressure switch, Ashcroft.
- Two safety shutoff valves each with a proof of closure switch, cast iron body, Maxon CC-5000.
- Two safety shutoff valve leak test valves.
- One vent valve, cast iron body, Maxon.
- One vent manual test valve, bronze body.
- One manual shutoff valve, cast iron body.
- One high pressure switch, Ashcroft.
- One Main pneumatic flow control valve, 125# FF cast iron body, with smart I/P positioner, mechanical down stop and low fire switch.
- Two burner pressure gauges, 4-1/2" Ashcroft.

Fyr-Monitor BMS and CCS (Metering) Control Panel (Qty: 1)

Fyr-Monitor touchscreen control system which will have burner management system (BMS) and combustion controls system (CCS) in the same panel and will use same touchscreen. The CCS type is Metering with fully-metered cross limiting, O2 trim, FGR trim, 3-Element Feedwater and Draft controls. Two PLCs will be used, one for BMS and one for CCS. The touchscreen will be a 10.4" CTC color screen and will have the following control screens.

(Rainhood not included)

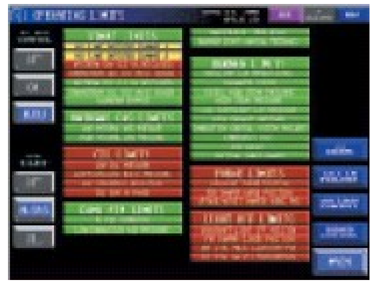


Main
Opening screen which shows control loops and pertinent BMS information for starting and monitoring burner.

Navigator
Provides access to other screens except system setup screens

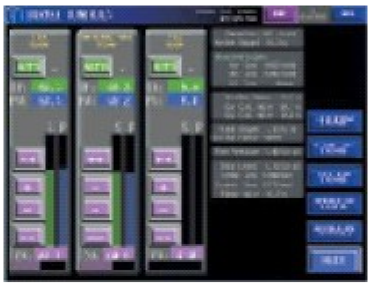
Surface Clean Allows screen cleaning without changing control settings

Flow Diagram
Piping style diagram of whole boiler process with numerical readouts of measured process values and showing valves open or closed, etc.



Alarm Status
Displays current alarm conditions in an annunciator style layout.

Alarm History Logs most recent alarm conditions.



Burner Control
Detailed information about all the control loops in the system.

Trending
Trends of all process variables controlled by the Fyr Monitor. Note, data is not stored, just shown for about 30 minutes of operation.

Two Allen Bradley PLCs will be mounted in a panel which will house all the necessary I/O modules, relays, terminals, etc. The following is included:

- (2) Allen Bradley CompactLogix PLC with all required I/O modules
- CTC touchscreen panel with 256 colors and TFT (active matrix) LCD.
  - o Size: 10.4”
- Memory: 8 megabyte flash ROM, 8 megabyte RAM
- The above items mounted in Nema 4X enclosure 48” x 36” x 24

Scanner system is as follows:

Coen system consisting of the following equipment:

Scanner Model: (2) Fireye scanners
Note: Scanner(s) require cooling/purge air.

<u>Loose pressure limits included</u>: (Qty: 1 ea)
- One Excess Steam pressure switch
- One High Furnace pressure switch
- One Low Combustion Air flow switch
- One Low Purge Air flow switch
- One Low Instrument Air pressure switch

3.2 Items Not Included In our Proposal- Existing

- Remove, disposal, demolition etc of existing equipment to allow for new equipment.
- Installation of new equipment
- Removal of windbox, DAF burner and throat
- Modification to the boiler front wall (as required) including all material and installation for the new RMB throat.
- Pipe, fittings, ducting, gaskets, wire and conduit as required for installation of valves, dampers and Fyr-Monitor panels
- Boiler drum level probes
- Boiler auxiliary drum level cut-out switch
- New FD fan package foundation
- New FD fan outlet duct including expansion joint to connect FD fan outlet to the
- New windbox damper inlet connection
- New FD Fan inlet supports (as required to support inlet silencer/FGR box).
- New FGR ducting, expansion joint, supports, connectors, etc.
- New FD Fan motor starter or VFD
- Any Pressure safety switches not listed above for BMS interface per NFPA-85
- Reuse Feedwater controls and instruments
- Reuse Draft controls
- O2 analyzer
- Source of ignitor/scanner cooling/purge air
- All insulation and lagging
- Erection
- Start-up Service
- Freight

4.0 Price

Budget: One RMB ULN unit as detailed below will be
SEVEN HUNDRED & FIFTY THOUSHAND DOLLARS ....**$750,000.00**.
The following equipment changes from the Base offering to be included.

Price Validity: Above prices are valid for acceptance by May 1, 2012 for delivery within 30 weeks of receipt of order unless otherwise specified. See Schedule section, below, for estimated lead times.

Prices do not include taxes. Freight cost is not included in our price. Equipment will be shipped Ex-works. point of manufacture, freight collect.

5.0 Payment

Subject to credit approval, progress payments will be required according to the following schedule: Net 30 days

15% of total order upon issuance of the purchase order or contract
30% on drawing transmittal
45% six (6) weeks after drawing transmittal
10% upon notice of availability of shipment

Escalation charges shall be applied to orders whose delivery dates are delayed beyond thirty (30) days from the contractual delivery date due to no fault of Coen and when such delay has caused an increase in the cost of the goods or services to Coen. Escalation charges shall be based upon either: (1) the Producer Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics for Finished Goods, Capital Equipment only, or (2) the U.S. Department of Labor, Employment Cost Index (ECI), Private Industry, Table 3. Employment Cost Index for total compensation for private industry workers, by industry and occupational group; Manufacturing Industry, as applicable. The base line for calculating the adjustment shall be the date of the contract.

6.0 Drawing and Schedule

Drawings will be submitted eight (8) weeks after receipt of purchase order and all engineering information. Shipment will be fourteen (14) weeks from receipt of approved drawings. Note: Actual dates will be confirmed upon receipt of the purchase order and scheduling meeting completed.

The following drawings/documents will be submitted for approval:

General Arrangement Drawing - Windbox-burner-trains
General Arrangement Drawing - Burner
Flow Diagram
Fyr-Monitor BMS/CCS Enclosure and Wiring Schematic
Fyr-Monitor BMS Sequence of Operation
Fyr-Monitor CCS Controls Narrative
Bill of Materials
IOM manual

7.0 Clarifications and Exceptions to the Specifications

None received. Coen standard scope, design, material and fabrication to be supplied

8.0 Terms & Conditions of Sale

This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes and does not constitute a commitment or offer to sell goods or services at the prices and terms referenced herein. Any firm offer or binding quotation will be the subject of a formal proposal at a future date.

To the extent an order is issued by you and accepted by Coen, then the resulting contract documents shall be subject to the attached Coen Company, Inc. Standard Terms and Conditions of Sale (the “T&Cs”) and this proposal (including, without limitation, the T&Cs) shall be incorporated by reference into such contract documents. In the case of a conflict among the contract documents, then the terms of the proposal (including, without limitation, the T&Cs) shall take precedence.

This proposal document is confidential and intended solely for the use of the individual or entity to which it is addressed. If you have received this proposal in error, please contact the sender and destroy all copies of the original message.

Regards,

Wayne A. Wieszczyk
Sr. Application Engineer
Boiler Burner Group
Coen Company Inc.
2151 River Plaza Dr, Suite 200
Sacramento, CA 95833
COEN TODD HAMWORTHY PEABODY
Ph: 650-522-2128
Fax: 650-522-2171
Cell: 530-867-2856
wayne.wieszczyk@coen.com
www.coen.com

Appendix C: Project Emissions Inventory Summaries

PSD APPLICABILITY SUMMARIES

Emissions Changes: Project Only, No Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
Baseline Actual Emissions (BAE) for Project	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	8.0	1,165,771	1,167,598
Package Boiler Emissions (PTE = PAE) >	8.3	8.3	8.3	12.2	41.2	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (PAE) >	224.7	224.7	224.7	503.3	5955.0	4.4	1873.7	0.028	9.6	1,529,044	1,531,350
Projected Actual Emissions (PAE) for Project	233.0	233.0	233.0	515.5	5996.1	5.0	1879.7	0.029	9.6	1,659,093	1,661,614
Project Emissions Increase	50.2	50.2	50.2	101.4	1564.8	0.8	438.6	0.005	1.6	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Is the Project Emissions Increase Significant?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

Net Emissions Changes: Includes Both Project and Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
Package Boiler Emissions (Project)	8.3	8.3	8.3	12.2	41.2	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (Project)	41.9	41.9	41.9	89.1	1523.7	0.1	432.6	0.005	1.6	363,273	363,752
Project Subtotal >	50.2	50.2	50.2	101.4	1564.8	0.8	438.6	0.005	1.6	493,321	494,015
New Contemporaneous Sources	22.1	22.1	22.1	37.5	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Increases	7.2	7.2	7.2	1.1	0	N/A	0	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Decreases	-0.1	-0.1	-0.1	0	0	N/A	0	N/A	N/A	0	0
Contemporaneous Subtotal >	29.2	29.2	29.2	38.6	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Sum of Project and Contemporaneous Emissions	79.4	79.4	79.4	140.0	1594.1	N/A	447.8	N/A	N/A	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Trigger PSD?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

* The increase in GHG emissions from the project (i.e., package boiler and debottlenecked sources) is significant and there are no creditable contemporaneous decreases of GHG. Thus, project clearly triggers PSD for GHG (BACT for the package boiler applies regardless) and no further quantification is performed.

Blue values are input values and black are calculated values.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC.	PROJECT NO: 170-12-2	PAGE: 2	OF: 5	SHEET: Applicability
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: December 10, 2012		

SUMMARY OF BASELINE ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	Package Boiler	New	0	0	0	0	0	0	0	0	0	0
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	0.0	0.0	0.0	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	8.6	8.6	8.6	0	0	0	0	0	117,265	117,265
16	Dryer Area	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	61.4	61.4	61.4	268.5	1252.6	4.2	1236.1	0.0225	372,352	373,965
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	10.3	10.3	10.3	5.1	528.7	0	71.4	0.0001	76,128	76,157
50	"C" Train Dryer Area	Debottlenecked	2.9	2.9	2.9	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	3.7	3.7	3.7	35.7	178.7	0	1.1	0.0002	153,323	153,363
52	Product Silo - Top #2	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	0.8	0.8	0.8	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.4	10.4	10.4	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.6	3.6	3.6	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	32.0	32.0	32.0	46.6	2444.1	0	131.4	0.0004	275,796	275,899
81	"D" Train Dryer Area	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	10.6	10.6	10.6	58.2	27.2	0	1.1	0.0002	170,906	170,949
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.2	0.2	0.2	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	1,165,771	1,167,598

SUMMARY OF BASELINE ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	0.2	0	N/A	0	N/A
35	Sulfite Dryer	Existing	3.24	3.24	3.24	0	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0.13	0.13	0.13	0	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0.13	0.13	0.13	0	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0.13	0.13	0.13	0	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0.01	0.01	0.01	0	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0.02	0.02	0.02	0	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	0.06	0.06	0.06	0	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0.02	0.02	0.02	0	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0	0	0	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	0.08	0.08	0.08	0	0	N/A	0	N/A
105	S-300 Dryer #1	New	0	0	0	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0	0	0	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	0	0	0	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0	0	0	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	0	0	N/A	0	N/A
E4	GM 8.1L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
E5	GM 4.3L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	0	0	N/A	0	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0	0	0	0	0	N/A	0	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0	0	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	0	0	N/A	0	N/A
		Total >	3.8	3.8	3.8	0.2	0	N/A	0	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary.

SUMMARY OF PROJECTED ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	Package Boiler	New	8.3	8.3	8.3	12.2	41.2	0.7	6.0	0.001	130,049	130,264
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	5.3	5.3	5.3	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	9.2	9.2	9.2	0	0	0	0	0	152,304	152,304
16	Dryer Area	Debottlenecked	3.9	3.9	3.9	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	71.8	71.8	71.8	321.2	1554.9	4.4	1498.1	0.0269	470,255	472,272
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	21.5	21.5	21.5	12.0	1238.0	0	197.1	0.0003	184,152	184,218
50	"C" Train Dryer Area	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	4.4	4.4	4.4	41.3	206.7	0	1.3	0.0002	177,020	177,066
52	Product Silo - Top #2	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	2.0	2.0	2.0	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.7	10.7	10.7	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	41.3	41.3	41.3	55.7	2921.3	0	176.0	0.0005	330,014	330,138
81	"D" Train Dryer Area	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	12.4	12.4	12.4	73.0	34.1	0	1.3	0.0002	215,298	215,352
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.9	0.9	0.9	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	233.0	233.0	233.0	515.5	5996.1	5.0	1879.7	0.0287	1,659,093	1,661,614

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 5	OF: 5	SHEET: Applicability
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: December 10, 2012		

AIR SCIENCES INC.

DENVER • PORTLAND

SUMMARY OF PROJECTED ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	1.3	0	N/A	0	N/A
35	Sulfite Dryer	Existing	6.13	6.13	6.13	0	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0.35	0.35	0.35	0	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0.31	0.31	0.31	0	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	1.18	1.18	1.18	0	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0.22	0.22	0.22	0	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0.22	0.22	0.22	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	1.31	1.31	1.31	0	0	N/A	0	N/A
105	S-300 Dryer #1	New	5.6	5.6	5.6	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0.3	0.3	0.3	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	5.6	5.6	5.6	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0.3	0.3	0.3	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0.9	0.9	0.9	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	8.9	8.9	8.9	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	2.7	3.9	N/A	1.9	N/A
E4	GM 8.1L (GVBH Pump)	New	0	0	0	1.4	2.0	N/A	1	N/A
E5	GM 4.3L (GVBH Pump)	New	0	0	0	0.8	1.2	N/A	0.6	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	25.7	15.0	N/A	3.6	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0.2	0.2	0.2	2.6	3.2	N/A	0.4	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0.6	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0.1	0.1	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	1.2	1.2	N/A	0.8	N/A
		Total >	33.1	33.1	33.1	38.8	29.3	N/A	9.2	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary.

SOLVAY2016_1.2_000764

Appendix D: Boiler Emissions and Stack Parameters

Package Boiler Information			Reference
Boiler Size	254	MMBtu/hour	Manufacturer specifications
Hours of operation	8760	hr/year	
Natural gas thermal equivalent	1020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)

EMISSIONS OF CRITERIA POLLUTANTS

Pollutant	g/sec	Emissions lb/hr	ton/year
NO_x	0.35	2.79	12.2
CO	1.18	9.40	41.2
Lead	0.00002	0.0001	0.001
PM (Total)	0.24	1.89	8.3
PM (Condensable)	0.18	1.42	6.2
PM (Filterable)	0.06	0.47	2.1
SO_2	0.02	0.15	0.7
VOC	0.17	1.37	6.0

EMISSION FACTORS

Pollutant	EF	unit	EF *	unit *	Reference
NO_x	9	ppm **			Manufacturer specifications
CO	50	ppm **			Manufacturer specifications
Lead	0.0005	lb/10^6 scf	4.90E-07	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
PM (Total)	7.6	lb/10^6 scf	7.45E-03	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
PM (Condensable)	5.7	lb/10^6 scf	5.59E-03	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
PM (Filterable)	1.9	lb/10^6 scf	1.86E-03	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
SO_2	0.6	lb/10^6 scf	5.88E-04	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
VOC	5.5	lb/10^6 scf	5.39E-03	lb/MMBtu	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)

* Per AP-42, Section 1.4, Table 1.4-2, to convert the AP-42 emission factors in lb/MMscf to lb/MMBtu divide by 1020.
** PPM value assumed to be by volume and under dry conditions at 3% O_2

NOx and CO Concentration Conversion Factors			Reference
F-Factor, Fd	8710	dscfm/MMBtu	EPA Reference Method 19, Table 19-2 for Natural Gas
O_2 (% dry), O_2d%	3	%	Manufacturer specifications
Molecular weight of NO_2, M_W	46.01	lb/mole	
Molecular weight of CO, M_W	28.00	lb/mole	
Molar volume of air at standard conditions, V_{M*}	385.3	scf/mole	
NOx conversion factor; 1 ppm NOx =	1.194E-07	lb/dscf at 0% O_2	EPA Reference Method 19, Table 19-1
CO conversion factor; 1 ppm CO =	7.267E-08	lb/dscf at 0% O_2	Calculated value (M_W/V_M)

* WAQSR, Chapter 1, Section 3 definition of "standard conditions"; temperature of 68 deg F, pressure reduced to 29.92" Hg at sea level.

NOx and CO Emission Factors for ULNB-FGR			Reference
NOx Emissions	9	ppm at 3% O_2*	Manufacturer specifications
	0.011	lb/MMBtu **	
CO Emissions	50	ppm at 3% O_2*	Manufacturer specifications
	0.037	lb/MMBtu **	

* ppm value assumed to be by volume and under dry conditions
** Emissions in ppm converted to lb/MMBtu using EPA Method 19, Equation 19-1 where:

E (lb/MMBtu) = Cd x Fd x [(20.9/(20.9 - O_2d%)]

Cd = Pollutant Concentration, dry basis, 0% O_2 (lb/dscf)
= emissions in ppm x (NOx ppm to lb/dscf conversion factor)
(the lb/dscf conversion factor is the molecular weight of pollutant, M_W, in lb/mole divided by the molar volume of air, V_M, in scf/mole).

Fd = F-Factor, volume of combustion components per unit of heat content

%O_2d = Concentration of O_2 in Exhaust Gas, %

Conversions	
453.59	g/lb
2000	lb/ton
3600	sec/hr
2.20462	lb/kg

Values in blue are input, values in black are calculated.

ESTIMATED BOILER STACK PARAMETERS

Parameter	Value		Reference
Stack Height	180	feet	Solvay
	54.86	meters	
Stack Diameter	6.0	feet	Solvay
	1.83	meters	
Flue gas temperature	350	°F	Manufacturer specifications
	450	°K	
Assumed standard temperature	68	°F	WDEQ standard per WAQSR, Chapter 1, Section 3
	293	°K	
Assumed standard pressure	29.92	"Hg	WDEQ standard per WAQSR, Chapter 1, Section 3
Assumed actual facility pressure (~6250 ft elevation) *	23.75	"Hg	
Exhaust moisture content	16.4	%	Manufacturer specifications
	0.1636	fraction	
Exhaust airflow	51,041	wscfm	Manufacturer specifications
	42,691	dscfm	

Estimated actual exhaust airflow

$$42{,}691 \text{ dscfm} \times \frac{450\ °K\ (T\ Actual)}{293\ °K\ (T\ Std\text{-}68F)} \times \frac{29.92\ "Hg\ (P\text{-}Std\text{-}1\ atm)}{23.75\ "Hg\ (P\text{-}Actual)} \times \frac{(moisture\ adjustment)}{1 - 0.1636} = 98{,}657 \text{ acfm}$$

* http://www.engineeringtoolbox.com/air-altitude-pressure-d_462.html

Exit velocity	58.2	ft/sec
	17.7	meters/sec

BOILER GREENHOUSE GAS EMISSIONS

Pollutant	EF	unit	Multiplier	GHG Mass-Based ton/year	CO_2e based ton/year
CO_2	53.02	kg/MMBtu	1	130,041	130,041
CH_4	0.001	kg/MMBtu	21	2.45	51.51
N_2O	0.0001	kg/MMBtu	310	0.25	76.03
Total GHGs				130,044	130,169

CO_2 equivalence (CO_2e) is calculated as follows:

CO_2e (ton/year) = (CO_2 ton/year x 1)+(CH_4 ton/year x 21)+(N_2O ton/year x 310)

EMISSION FACTORS

Pollutant	EF	unit	Reference	Global Warming Potential (100 yr.)	Reference
CO_2	53.02	kg/MMBtu	40 CFR Part 98, Subpart C, Table C-1 (Natural Gas)	1	40 CFR 98, Table A-1
CH_4	0.001	kg/MMBtu	40 CFR Part 98, Subpart C, Table C-2 (Natural Gas)	21	40 CFR 98, Table A-1
N_2O	0.0001	kg/MMBtu	40 CFR Part 98, Subpart C, Table C-2 (Natural Gas)	310	40 CFR 98, Table A-1

BOILER HAP EMISSIONS

Pollutant	EF (lb/10^6 scf)	EF (lb/MMBtu) *	Emissions g/sec	Emissions lb/hr	Emissions ton/year
2-Methylnaphthalene (91-57-6)	2.40E-05	2.35E-08	7.53E-07	5.98E-06	2.62E-05
3-Methylchloranthrene (56-49-5)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	5.02E-07	3.98E-06	1.75E-05
Acenaphthene (83-32-9)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Acenaphthylene (203-96-8)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Anthracene (120-12-7)	2.40E-06	2.35E-09	7.53E-08	5.98E-07	2.62E-06
Arsenic (7440-38-2)	2.00E-04	1.96E-07	6.28E-06	4.98E-05	2.18E-04
Benz(a)anthracene (56-55-3)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Benzene (71-43-2)	2.10E-03	2.06E-06	6.59E-05	5.23E-04	2.29E-03
Benzo(a)pyrene (50-32-8)	1.20E-06	1.18E-09	3.77E-08	2.99E-07	1.31E-06
Benzo(b)fluoranthene (205-99-2)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Benzo(g,h,i)perylene (191-24-2)	1.20E-06	1.18E-09	3.77E-08	2.99E-07	1.31E-06
Benzo(k)fluoranthene (205-82-3)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Beryllium (7440-41-7)	1.20E-05	1.18E-08	3.77E-07	2.99E-06	1.31E-05
Cadmium (7440-43-9)	1.10E-03	1.08E-06	3.45E-05	2.74E-04	1.20E-03
Chromium (7440-47-3)	1.40E-03	1.37E-06	4.39E-05	3.49E-04	1.53E-03
Chrysene (218-01-9)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Cobalt (7440-48-4)	8.40E-05	8.24E-08	2.64E-06	2.09E-05	9.16E-05
Dibenzo(a,h)anthracene (53-70-3)	1.20E-06	1.18E-09	3.77E-08	2.99E-07	1.31E-06
Dichlorobenzene (25321-22-6)	1.20E-03	1.18E-06	3.77E-05	2.99E-04	1.31E-03
Fluoranthene (206-44-0)	3.00E-06	2.94E-09	9.41E-08	7.47E-07	3.27E-06
Fluorene (86-73-7)	2.80E-06	2.75E-09	8.79E-08	6.97E-07	3.05E-06
Formaldehyde (50-00-0)	7.50E-02	7.35E-05	2.35E-03	1.87E-02	8.18E-02
Hexane (110-54-3)	1.8	1.76E-03	5.65E-02	4.48E-01	1.96E+00
Indeno(1,2,3-cd)pyrene (193-39-5)	1.80E-06	1.76E-09	5.65E-08	4.48E-07	1.96E-06
Manganese (7439-96-5)	3.80E-04	3.73E-07	1.19E-05	9.46E-05	4.14E-04
Mercury (7439-97-6)	2.60E-04	2.55E-07	8.16E-06	6.47E-05	2.84E-04
Naphthalene (91-20-3)	6.10E-04	5.98E-07	1.91E-05	1.52E-04	6.65E-04
Nickel (7440-02-0)	2.10E-03	2.06E-06	6.59E-05	5.23E-04	2.29E-03
Phenanathrene (85-01-8)	1.70E-05	1.67E-08	5.33E-07	4.23E-06	1.85E-05
Pyrene (129-00-0)	5.00E-06	4.90E-09	1.57E-07	1.25E-06	5.45E-06
Selenium (7782-49-2)	2.40E-05	2.35E-08	7.53E-07	5.98E-06	2.62E-05
Toluene (108-88-3)	3.40E-03	3.33E-06	1.07E-04	8.47E-04	3.71E-03
Highest HAP (Hexane)			0.06	0.45	1.96
Total HAP			0.12	0.92	4.02

Emission factors from AP-42, Section 1.4 - "Natural Gas Combustion," Tables 1.4.3 and 1.4-4 (Revision 7/98).
* Per AP-42, Section 1.4, Table 1.4-2, to convert the AP-42 emission factors in lb/MMscf to lb/MMBtu divide by 1020.

Appendix E: Debottlenecked Source Emissions

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 1	OF: 4	SHEET: Debottleneck
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: November 6, 2012		

DEBOTTLENECKED SOURCES LIST

WDEQ Source ID	Source Description	Type	Combustion Source?	Fuel(s)
02A	Ore Crusher Building #1	Existing Baghouse	No	---
06A	Product Silos - Top #1	Existing Baghouse	No	---
06B	Product Silos - Bottom #1	Existing Baghouse	No	---
07	Product Loadout Station	Existing Baghouse	No	---
15	DR-1 & 2 Steam Tube Dryers	Existing Combustion, Scrubber	No*	None
16	Dryer Area	Existing Baghouse	No	---
17	"A" and "B" Calciners	Existing Combustion, ESP	Yes	Coal
46	Ore Transfer Station	Existing Baghouse	No	---
48	"C" Calciner	Existing Combustion, ESP	Yes	Gas
50	"C" Train Dryer Area	Existing Baghouse	No	---
51	Product Dryer #5	Existing Combustion, ESP	Yes	Gas
52	Product Silo - Top #2	Existing Baghouse	No	---
53	Product Silo - Bottom #2	Existing Baghouse	No	---
76	"D" Train Primary Ore Screening	Existing Baghouse	No	---
79	Ore Transfer Point	Existing Baghouse	No	---
80	"D" Ore Calciner	Existing Combustion, ESP	Yes	Gas
81	"D" Train Dryer Area	Existing Baghouse	No	---
82	DR-6 Product Dryer	Existing Combustion, ESP	Yes	Gas
99	Crusher Baghouse #2	Existing Baghouse	No	---
100	Calciner Coal Bunker	Existing Baghouse	No	---
103	East Ore Reclaim	Existing Baghouse	No	---
104	West Ore Reclaim	Existing Baghouse	No	---

* Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used so there are no actual gaseous emissions.

ACTUAL ANNUAL OPERATING HOURS AND THROUGHPUTS - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ		Annual Operating Hours (hr/yr)					Throughput (ton/yr)				
Source ID	Source Description	2006	2007	2008	2009	2010	2006	2007	2008	2009	2010
02A	Ore Crusher Building #1	8,760	8,760	8,784	8,760	8,760	2,074,199	1,675,635	2,438,586	2,095,363	1,718,011
06A	Product Silos - Top #1	8,760	8,760	8,784	8,760	8,760	148,728	180,850	128,474	96,018	127,374
06B	Product Silos - Bottom #1	225	262	187	150	187	172,865	175,235	122,735	99,901	131,979
07	Product Loadout Station	3,744	3,744	3,744	3,744	3,744	2,801,210	2,585,713	2,522,814	2,316,345	2,522,504
15	DR-1 & 2 Steam Tube Dryers	8,364	8,408	8,159	8,131	8,392	967,105	944,140	755,359	786,186	771,037
16	Dryer Area	8,364	8,408	8,159	8,131	8,392	967,105	944,140	755,359	786,186	771,037
17	"A" and "B" Calciners	8,507	8,627	8,344	8,673	8,276	1,202,621	1,592,932	1,566,774	1,773,989	1,439,276
46	Ore Transfer Station	8,760	8,760	8,784	8,760	8,760	2,074,199	1,675,635	2,438,586	2,095,363	1,718,011
48	"C" Calciner	7,580	4,813	3,739	4,420	3,853	1,046,548	540,553	422,508	443,485	476,594
50	"C" Train Dryer Area	8,027	8,361	8,473	8,029	8,432	722,311	819,929	805,135	729,938	812,220
51	Product Dryer #5	8,027	8,361	8,473	8,029	8,432	722,311	819,929	805,135	729,938	812,220
52	Product Silo - Top #2	8,717	8,466	8,473	8,404	8,539	2,330,072	2,402,715	2,441,008	2,304,423	2,420,111
53	Product Silo - Bottom #2	3,519	3,482	3,557	3,594	3,557	2,628,345	2,410,478	2,400,079	2,216,444	2,390,525
76	"D" Train Primary Ore Screening	7,684	8,559	7,925	8,680	8,343	1,884,419	2,371,036	1,603,534	1,655,777	2,367,952
79	Ore Transfer Point	7,684	8,559	7,925	8,680	8,343	1,884,419	2,371,036	1,603,534	1,655,777	2,367,952
80	"D" Ore Calciner	7,671	7,655	8,133	6,254	8,099	1,516,472	1,677,003	1,792,095	1,300,723	1,814,177
81	"D" Train Dryer Area	8,689	8,466	8,400	8,098	8,539	789,384	819,496	1,008,988	884,317	964,228
82	DR-6 Product Dryer	8,689	8,466	8,400	8,098	8,539	789,384	819,496	1,008,988	884,317	964,228
99	Crusher Baghouse #2	8,760	8,760	8,784	8,760	8,760	2,074,199	1,675,635	2,438,586	2,095,363	1,718,011
100	Calciner Coal Bunker	1,245	1,969	1,945	2,021	2,043	47,086	102,883	101,966	112,190	101,167
103	East Ore Reclaim	8,059	8,760	8,784	8,760	8,760	1,908,263	1,675,635	1,219,293	1,047,682	859,006
104	West Ore Reclaim	8,059	8,760	8,784	8,760	8,760	1,908,263	1,675,635	1,219,293	1,047,682	859,006

Blue values are input values and black are calculated values.

PROJECTED EMISSIONS INCREASES FROM DEBOTTLENECKED SOURCES; PARTICULATES

Assumptions:

1) There are no short-term increases in PTE for all sources.
2) No existing debottlenecked sources will be physically modified.

3) The average production over the past five years is: 2,549,717 tons/year (based on avg. throughput for AQD #7 from 2006 to 2010)
4) Debottleneck results in production increase of: 360,000 tons/year
5) Assume projected annual emissions of non-baghouse sources are a function of the production increase (%): 14.1%

Particulates (PM)

WDEQ Source ID	Source Description	Actual Annual PM Emissions (tons/yr)[1] 2006	2007	2008	2009	2010	2009-2010 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
02A**	Ore Crusher Building #1	7.0	7.0	7.0	7.0	7.0	7.0	7.0	0
06A**	Product Silos - Top #1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	0
06B***	Product Silos - Bottom #1	0.1	0.1	0.0	0.0	0.0	0.04	2.2	2.2
07***	Product Loadout Station	2.2	2.2	2.2	2.2	2.2	2.2	5.3	3.0
15***	DR-1 & 2 Steam Tube Dryers	8.7	8.8	8.5	8.5	8.8	8.6	9.2	0.5
16***	Dryer Area	3.8	3.8	3.7	3.7	3.8	3.7	3.9	0.2
17*	"A" and "B" Calciners	31.8	40.3	31.4	62.9	60.0	61.4	71.8	10.3
46**	Ore Transfer Station	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0
48*	"C" Calciner	18.8	12.0	9.3	11.0	9.6	10.3	21.5	11.2
50***	"C" Train Dryer Area	2.8	2.9	3.0	2.8	3.0	2.9	3.1	0.2
51*	Product Dryer #5	3.6	3.8	3.8	3.6	3.8	3.7	4.4	0.6
52***	Product Silo - Top #2	2.2	2.1	2.1	2.1	2.1	2.1	2.2	0.1
53***	Product Silo - Bottom #2	0.8	0.8	0.8	0.8	0.8	0.8	2.0	1.2
76***	"D" Train Primary Ore Screening	9.4	10.5	9.7	10.6	10.2	10.4	10.7	0.3
79***	Ore Transfer Point	3.2	3.6	3.3	3.6	3.5	3.6	3.7	0.1
80*	"D" Ore Calciner	34.2	34.1	36.2	27.9	36.1	32.0	41.3	9.4
81***	"D" Train Dryer Area	2.2	2.1	2.1	2.0	2.1	2.1	2.2	0.1
82*	DR-6 Product Dryer	10.1	9.8	10.7	10.3	10.8	10.6	12.4	1.8
99**	Crusher Baghouse #2	14.0	14.0	14.1	14.0	14.0	14.0	14.0	0
100***	Calciner Coal Bunker	0.1	0.2	0.2	0.2	0.2	0.2	0.9	0.7
103**	East Ore Reclaim	1.3	1.4	1.4	1.4	1.4	1.4	1.4	0
104**	West Ore Reclaim	1.1	1.2	1.2	1.2	1.2	1.2	1.2	0
	Subtotals >	---	---	---	---	---	182.8	224.7	41.9

[1] From Solvay's annual emission inventories submitted to WDEQ.

* For the combustion sources (#17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions.

** For baghouses which already operate 8760 hours per year (#02A, #06A, #46, #99, #103, #104), there will be no emissions increases and the emissions remain unchanged.

***For each baghouse (and source #15), the actual annual emissions reported to WDEQ are a function of the annual operating hours (not the throughputs). In other words, the hourly actual emission rate is a constant and the annual emissions totals are based on the annual operating hours of the source. For all baghouses which currently operate less than 8760 hours per year, the projected actual emissions are estimated by multiplying the ratio of annual emissions/annual hours (i.e., ton/hr emissions) by 8760 hours per year for each source to reflect post-project debottlenecked operations.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler		BY: T. Martin	
AIR SCIENCES INC. DENVER • PORTLAND	PROJECT NO: 170-12-2	PAGE: 3	OF: 4	SHEET: Debottleneck
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory		DATE: November 6, 2012	

PROJECTED EMISSIONS INCREASES FROM DEBOTTLENECKED SOURCES; GASEOUS POLLUTANTS

Assumptions:

1) There are no short-term increases in PTE for all sources.
2) No existing debottlenecked sources will be physically modified.

3) The average production over the past five years is: 2,549,717 tons/year (based on avg. throughput for AQD #7 from 2006 to 2010)
4) Debottleneck results in production increase of: 360,000 tons/year
5) Assume projected annual emissions of non-baghouse sources are a function of the production increase (%): 14.1%

NOx

WDEQ Source ID *	Source Description	Actual Annual NOx Emissions (tons/yr)[1] 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	134.9	281.5	255.4	281.4	228.9	268.5	321.2	52.8
48	"C" Calciner	10.5	5.8	4.4	5.0	4.7	5.1	12.0	6.9
51	Product Dryer #5	31.8	35.3	36.2	33.3	35.5	35.7	41.3	5.6
80	"D" Ore Calciner	38.2	44.4	48.9	34.6	45.5	46.6	55.7	9.1
82	DR-6 Product Dryer	53.1	52.4	64.0	56.0	59.5	58.2	73.0	14.8
	Subtotals >	---	---	---	---	---	414.2	503.3	89.1

CO

WDEQ Source ID *	Source Description	Actual Annual CO Emissions (tons/yr)[1] 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	906.5	1268.2	1237.0	1362.5	1229.7	1252.6	1554.9	302.3
48	"C" Calciner	1084.9	597.4	460.1	514.5	488.3	528.7	1238.0	709.3
51	Product Dryer #5	158.9	176.3	181.1	166.6	177.6	178.7	206.7	28.0
80	"D" Ore Calciner	2003.6	2328.3	2559.8	1812.2	2386.8	2444.1	2921.3	477.2
82	DR-6 Product Dryer	24.8	24.5	29.9	26.1	27.7	27.2	34.1	6.9
	Subtotals >	---	---	---	---	---	4431.3	5955.0	1523.7

SO_2

WDEQ Source ID **	Source Description	Actual Annual SO_2 Emissions (tons/yr)[1] 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	1.4	4.3	4.2	4.3	4.1	4.2	4.4	0.1
48	"C" Calciner	---	---	---	---	---	---	---	---
51	Product Dryer #5	---	---	---	---	---	---	---	---
80	"D" Ore Calciner	---	---	---	---	---	---	---	---
82	DR-6 Product Dryer	---	---	---	---	---	---	---	---
	Subtotals >	---	---	---	---	---	4.2	4.4	0.1

VOC

WDEQ Source ID *	Source Description	Actual Annual VOC Emissions (tons/yr)[1] 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	889.9	1178.8	1159.4	1312.8	1065.1	1236.1	1498.1	262.0
48	"C" Calciner	172.7	89.2	69.7	73.2	78.6	71.4	197.1	125.6
51	Product Dryer #5	1.0	1.1	1.1	1.0	1.1	1.1	1.3	0.2
80	"D" Ore Calciner	128.9	142.5	152.3	110.6	154.2	131.4	176.0	44.5
82	DR-6 Product Dryer	1.1	1.1	1.1	1.1	1.1	1.1	1.3	0.2
	Subtotals >	---	---	---	---	---	1441.1	1873.7	432.6

[1] From Solvay's annual emission inventories submitted to WDEQ.

* For the combustion sources (#17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions.

**Annual SO_2 emissions reported to WDEQ for #17 are based on 1.0 lb/hr emissions and the annual hours of operations of the source. The PAE for SO_2 is set as the PTE for the source (i.e., 1.0 lb/hr emissions for 8760 hours/year = 4.38 tpy).

PROJECTED EMISSIONS INCREASES FROM DEBOTTLENECKED SOURCES; LEAD AND FLUORIDES

Assumptions:

1) There are no short-term increases in PTE for all sources.
2) No existing debottlenecked sources will be physically modified.

3) The average production over the past five years is: 2,549,717 tons/year (based on avg. throughput for AQD #7 from 2006 to 2010)
4) Debottleneck results in production increase of: 360,000 tons/year
5) Assume projected annual emissions of non-baghouse sources are a function of the production increase (%): 14.1%

ACTUAL ANNUAL OPERATING FUEL CONSUMPTION - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ Source ID	Source Description	Fuel	Coal Consumption (tons/year) [1] 2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Coal	47,086	102,883	101,966	112,190	101,167

WDEQ Source ID	Source Description	Fuel	Gas Consumption (MMscf/year) [1] 2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Gas	507	---	---	---	---
48	"C" Calciner	Gas	1,004	555	432	484	463
51	Product Dryer #5	Gas	609	678	704	649	697
80	"D" Ore Calciner	Gas	1,465	1,709	1,899	1,347	1,788
82	DR-6 Product Dryer	Gas	678	672	829	727	778

[1] From Solvay's annual emission inventories submitted to WDEQ.

Lead

WDEQ Source ID *	Source Description	Fuel	Calculated Actual Annual Lead Emissions (tons/yr) 2006	2007	2008	2009	2010	2008 - 2009 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	Coal	0.0100	0.0216	0.0214	0.0236	0.0212	0.0225	0.0269	0.004
48	"C" Calciner	Gas	0.0003	0.0001	0.0001	0.0001	0.0001	0.0001	0.0003	0.0002
51	Product Dryer #5	Gas	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.00003
80	"D" Ore Calciner	Gas	0.0004	0.0004	0.0005	0.0003	0.0004	0.0004	0.0005	0.0001
82	DR-6 Product Dryer	Gas	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.00004
	Subtotals >		---	---	---	---	---	0.0234	0.0282	0.005

Fluorides (as hydrogen fluoride for coal combustion)

WDEQ Source ID *	Source Description	Fuel	Calculated Actual Annual Fluoride Emissions (tons/yr) 2006	2007	2008	2009	2010	2008 - 2009 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
17	"A" and "B" Calciners	Coal	3.5	7.7	7.6	8.4	7.6	8.0	9.6	1.6
48	"C" Calciner	Gas	---	---	---	---	---	---	---	---
51	Product Dryer #5	Gas	---	---	---	---	---	---	---	---
80	"D" Ore Calciner	Gas	---	---	---	---	---	---	---	---
82	DR-6 Product Dryer	Gas	---	---	---	---	---	---	---	---
	Subtotals >		---	---	---	---	---	8.0	9.6	1.6

* For the combustion sources (17, 48, 51, 80, 82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions.

Lead Emission Factors

Gas-fired	0.0005	lb/MMscf	AP-42, Section 1.4, Table 1.4-2 (Rev. 7/98)
Coal-fired	4.2E-04	lb/ton coal	AP-42, Section 1.1, Table 1.1-18 (Rev. 9/98) Trace metals from controlled coal combustion

Fluorides Emission Factors

Gas-fired	N/A		
Coal-fired	0.15	lb/ton coal	AP-42, Section 1.1, Table 1.1-15 (Rev. 9/98) Hydrogen Fluoride (HF) emissions from coal combustion

Conversions 2000 lb/ton

Appendix F: Contemporaneous Source Emissions

LIST OF PERMIT ACTIONS DURING CONTEMPORANEOUS PERIOD

WDEQ Reference	Date	WDEQ Source ID(s)	Source Description	New or Existing Source? [1]
MD-7431	09/02/08	105	S-300 Dryer #1	New
		106	S-300 Silo and Rail Loadout #1	New
		107	S-300 Dryer #2	New
		108	S-300 Silo and Rail Loadout #2	New
		15	DR-1 & 2 Steam Tube Dryers	Existing
		17	"A" & "B" Calciners	Existing
		48	"C" Calciner	Existing
		80	"D" Calciner	Existing
Waiver AP-8430	10/24/08	88b	Trona Products Transloading #3	New
MD-8929	05/26/09	N/A	DECA Excavation	New
		N/A	DECA Stockpiling	New
		N/A	DECA Haul Road Activity	New
		N/A	Tier III Diesel Engine, ≤ 175 hp	New
		N/A	DECA Melt Tank	New
MD-7431A	06/29/09	106, 108	S-300 Silo and Rail Loadout #1, #2	Changes to 9/2/08 action
Waiver AP-9390	07/10/09	E1	Engines to remove CH_4 from active mining	New
		E2	Engines to remove CH_4 from active mining	New
Waiver wv-10100	11/06/09	N/A	Temporary Trona Stockpile	New
Waiver wv-10115	02/19/10	88	Trona Products Transloading #2	Existing
		98	TPX Area	Existing
MD-10253	03/24/10	E3	Waukesha F18GSI (GVBH compressor)	New
		GVBH V	GVB Borehole Venting	Existing
		GVBH Fl	GVB Flare	New
MD-10561	07/13/10	E4	GM 8.2L (GVBH Pump)	New
		E5	GM 4.3L (GVBH Pump)	New
Waiver wv-10696	08/31/10	N/A	DECA Melt Tank	---
		N/A	DECA Stamler System	New - modification to 5/26/09
Division letter, Re AP-10381	09/15/10	33	Sulfur Burner	Existing
		35	Sulfite Dryer	Existing
		36	Sulfite Product Bin #1	Existing
		37	Sulfite Product Bin #2	Existing
		38	Sulfite Product Bin #3	Existing
		64	Sulfite Blending #2	Existing
		65	Sulfite Blending #1	Existing
		70	Sodium Sulfite Bagging Silo	Existing
		90	Blending Bag Dump #1	Existing
		91	Blending Bag Dump #2	Existing
		94	Sulfite Loadout	Existing
MD-11024	11/29/10	GVBH V	GVB Borehole Venting	Existing
MD-11835	06/21/11	EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New
		EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New
		EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New
		EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New
Waiver wv-11853	04/14/11	N/A	TEG Dehydration Unit	New
		N/A	Two (2) Reboilers Heaters	New
Waiver wv-11822	04/29/11	N/A	Katolight SENL80FGC4 NG-fired Generator	New
Waiver wv-12090	06/13/11	N/A	Temporary Trona Stockpile	New
Division letter, Re AP-11995	09/14/11	N/A	Diversion of material/clarification for DR-7	Existing
None; Solvay Permit App.	2012	N/A	Temporary Portable Boiler	New (Temporary)
This PSD permit action; pkg. boiler project		64, 65, 72, 89, 90, 91	---	Removal of Existing Sources

[1] Relative to the contemporaneous period which begins on the date 5 years before construction commences on the proposed modification and ends on the date the emissions increase from the particular change occurs (i.e., 2008 until first emissions from boiler project).

NON-CREDITABLE PERMIT ACTIONS/EMISSIONS DURING CONTEMPORANEOUS PERIOD

WDEQ Reference	Date(s)	WDEQ Source ID	Source Description	Source New or Existing? [1]	Source(s) Currently Permitted?	Reason Not Creditable
MD-7431	09/02/08	15 17 48 80	DR-1 & 2 Steam Tube Dryers "A" & "B" Calciners "C" Calciner "D" Calciner	Existing	Yes	Non-creditable reduction. [2]
MD-8929, wv-10696	05/26/09, 8/31/2010	N/A	Tier III Diesel Engine, ≤ 175 hp	New	No: removed under wv-10696	Source permitted and removed during contemporaneous period. Source no longer permitted.
Waiver wv-10100	11/06/09	N/A	Temporary Trona Stockpile	New	No: waiver expired 7/15/2010	Source was temporary and is no longer permitted.
Waiver wv-10115	02/19/10	88 98	Trona Products Transloading #2 TPX Area	Existing	Yes	No modification to either source. Project had insignificant changes to PM emissions.
Waiver AP-9390, MD-10561	7/10/09, 7/13/10	E1 E2	Engines to remove CH_4 from active mining	New	No: removed under MD-10561	Sources permitted and removed during contemporaneous period. Sources no longer permitted.
MD-11024 supersedes MD-10253	11/29/10	GVBH V	GVB Borehole Venting	Existing	No	No emissions changes. [3]
Waiver wv-12090	06/13/11	N/A	Temporary Trona Stockpile	New	No: waiver expired 11/1/2011	Source was temporary and is no longer permitted.
Division letter, Re AP-11995	09/14/11	N/A	Diversion of material/clarification for DR-7	Existing	Yes	No emissions increases associated with diversion of material or clarification of DR-7 feed rate: permit not required.
None; Solvay Permit Application	2012	N/A	Temporary Portable Boiler	New	No: permit application	Source is temporary and is to be removed before the larger package boiler from this PSD permit action begins operation.

[1] Relative to the contemporaneous period.

[2] PTE PM emissions levels for these sources were reduced, but the old level of actual emissions does not exceed the new level of actual emissions as required for emissions to be creditable. See WDEQ regulations Chapter 6, Section 4, part (vii)(A) - definition of "net emissions increase".

[3] In MD-10253, source was considered new, but given information in MD-11024, the source is considered existing as it has been demonstrated that the gas vented through the GVBs would otherwise be vented uncontrolled from the main mine ventilation system; thus the GVBs don't increase mine emissions.

CREDITABLE EMISSION INCREASES AT EXISTING SOURCES DURING CONTEMPORANEOUS PERIOD
(Division letter, Re AP-10381, 09/15/2010)

PM_{10} Increases

WDEQ Source ID	Source Description	Hours	BAE (tpy)	PTE (lb/hr)	PTE (tpy)	Net Increase (tpy)
33	Sulfur Burner	8760	---	---	---	---
35	Sulfite Dryer	8760	3.24	1.4	6.13	2.89
36	Sulfite Product Bin #1	8760	0.13	0.1	0.44	0.31
37	Sulfite Product Bin #2	8760	0.13	0.1	0.44	0.31
38	Sulfite Product Bin #3	8760	0.13	0.1	0.44	0.31
64	Sulfite Blending #2	8760	0.01	0.08	0.35	0.34
65	Sulfite Blending #1	8760	0.02	0.07	0.31	0.29
70	Sodium Sulfite Bagging Silo	8760	0.06	0.27	1.18	1.12
90	Blending Bag Dump #1	8760	0.02	0.05	0.22	0.20
91	Blending Bag Dump #2	8760	0.0	0.05	0.22	0.22
94	Sulfite Loadout	8760	0.08	0.3	1.31	1.23
	Subtotal >	---	3.8	---	11.0	7.2

NOx Increases

WDEQ Source ID	Source Description	Hours	BAE (tpy)	PTE (lb/hr)	PTE (tpy)	Net Increase (tpy)
33	Sulfur Burner	8760	0.2	0.3	1.3	1.1
	Subtotal >	---	0.2	---	1.3	1.1

CREDITABLE EMISSION DECREASES AT EXISTING SOURCES DURING CONTEMPORANEOUS PERIOD*

PM_{10} Decreases

WDEQ Source ID	Source Description	Actual Annual PM Emissions (tons/yr) [1] 2006	2007	2008	2009	2010	2009-2010 BAE (tons/yr)	PAE (tons/yr)	Decrease (PAE-BAE) (tons/year)
64	Sulfite Blending #2	0.01	0.01	0.01	0.004	0.004	0.004	0	-0.004
65	Sulfite Blending #1	0.03	0.02	0.02	0.01	0.02	0.01	0	-0.01
72	MBS Soda Ash Feed Silo	0.1	0.1	0.1	0.1	0.05	0.1	0	-0.1
90	Blending Bag Dump #1	0.02	0.02	0.02	0.01	0.01	0.01	0	-0.01
91	Blending Bag Dump #2	0.003	0.002	0.002	0.001	0.001	0.001	0	-0.001
	Subtotals >	---	---	---	---	---	0.1	0	-0.1

[1] From Solvay's annual emission inventories submitted to WDEQ.
* From sources to be removed from the facility as part of this PSD permit action.

CREDITABLE EMISSION INCREASES AT NEW SOURCES DURING CONTEMPORANEOUS PERIOD

List of New Sources and Related Permitting Information

WDEQ Source ID	Source Description	WDEQ Reference	Date(s)
105	S-300 Dryer #1	MD-7431	9/2/08
106	S-300 Silo and Rail Loadout #1	MD-7431, MD-7431A	9/2/08, 6/29/09
107	S-300 Dryer #2	MD-7431	9/2/08
108	S-300 Silo and Rail Loadout #2	MD-7431, MD-7431A	9/2/08, 6/29/09
88b	Trona Products Transloading #3	Waiver AP-8430	10/24/08
N/A	DECA Excavation	MD-8929	5/26/09
N/A	DECA Stockpiling	MD-8929	5/26/09
N/A	DECA Haul Road Activity	MD-8929	5/26/09
N/A	DECA Melt Tank	MD-8929	5/26/09
E3	Waukesha F18GSI (GVBH compressor)	MD-10253, MD-11024	3/24/10, 11/29/10
E4	GM 8.2L (GVBH Pump)	MD-10561	07/13/10
E5	GM 4.3L (GVBH Pump)	MD-10561	07/13/10
N/A	DECA Stamler System	Waiver wv-10696, modifies MD-8929	08/31/10
GVBH Fl	GVB Flare	MD-11024 supersedes MD-10253	11/29/10
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	MD-11835	06/21/11
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	MD-11835	06/21/11
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	MD-11835	06/21/11
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	MD-11835	06/21/11
N/A	TEG Dehydration Unit	Waiver wv-11853	04/14/11
N/A	Two (2) Reboilers Heaters	Waiver wv-11853	04/14/11
N/A	Katolight SENL80FGC4 NG-fired Generator	Waiver wv-11822	04/29/11

CREDITABLE EMISSION INCREASES AT NEW SOURCES DURING CONTEMPORANEOUS PERIOD, CONTD.

PTE Emissions for New Sources

WDEQ Source ID	Source Description	Operating Hours	PM_{10} (lb/hr)	PM_{10} (tons/yr)	NOx (lb/hr)	NOx (tons/yr)	CO (lb/hr)	CO (tons/yr)
105	S-300 Dryer #1	8760	1.3	5.6	---	---	---	---
106	S-300 Silo and Rail Loadout #1	8760	0.1	0.3	---	---	---	---
107	S-300 Dryer #2	8760	1.3	5.6	---	---	---	---
108	S-300 Silo and Rail Loadout #2	8760	0.1	0.3	---	---	---	---
88b	Trona Products Transloading #3	8760	0.2	0.9	---	---	---	---
N/A	DECA Excavation	---	< 0.1 tpy; insignificant		---	---	---	---
N/A	DECA Stockpiling	---	< 0.1 tpy; insignificant		---	---	---	---
N/A	DECA Haul Road Activity	8760	2.0	8.9	---	---	---	---
N/A	DECA Melt Tank	---	---	---	---	---	---	---
E3	Waukesha F18GSI (GVBH compressor)	8760	---	---	0.6	2.7	0.9	3.9
E4	GM 8.2L (GVBH Pump)	8760	---	---	0.3	1.4	0.5	2.0
E5	GM 4.3L (GVBH Pump)	8760	---	---	0.2	0.8	0.3	1.2
N/A	DECA Stamler System	---	---	---	---	---	---	---
GVBH Fl	GVB Flare	8760	---	---	5.9	25.7	3.4	15.0
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	500	0.6	0.2	10.5	2.6	12.9	3.2
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	4.0	1.0	3.5	0.9
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	4.0	1.0	3.5	0.9
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	4.0	1.0	3.5	0.9
N/A	TEG Dehydration Unit	8760	---	---	---	---	---	---
N/A	Two (2) Reboilers Heaters	8760	< 0.1 tpy; insignificant		0.02	0.1	0.02	0.1
N/A	Katolight SENL80FGC4 NG-fired Generator	8760	---	---	0.3	1.2	0.3	1.2
	Subtotal >	---	---	22.1	---	37.5	---	29.3

PTE Emissions for New Sources

WDEQ Source ID	Source Description	Operating Hours	SO_2 (lb/hr)	SO_2 (tons/yr)	VOC (lb/hr)	VOC (tons/yr)
105	S-300 Dryer #1	8760	---	---	---	---
106	S-300 Silo and Rail Loadout #1	8760	---	---	---	---
107	S-300 Dryer #2	8760	---	---	---	---
108	S-300 Silo and Rail Loadout #2	8760	---	---	---	---
88b	Trona Products Transloading #3	8760	---	---	---	---
N/A	DECA Excavation	---	---	---	---	---
N/A	DECA Stockpiling	---	---	---	---	---
N/A	DECA Haul Road Activity	8760	---	---	---	---
N/A	DECA Melt Tank	---	---	---	---	---
E3	Waukesha F18GSI (GVBH compressor)	8760	---	---	0.4	1.9
E4	GM 8.2L (GVBH Pump)	8760	---	---	0.2	1.0
E5	GM 4.3L (GVBH Pump)	8760	---	---	0.1	0.6
N/A	DECA Stamler System	---	---	---	---	---
GVBH Fl	GVB Flare	8760	---	---	0.8	3.6
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	500	0.3	0.1	1.5	0.4
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	0.3	0.1
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	0.3	0.1
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	500	0.2	0.1	0.3	0.1
N/A	TEG Dehydration Unit	8760	---	---	---	0.6
N/A	Two (2) Reboilers Heaters	8760	---	---	< 0.1 tpy; insignificant	
N/A	Katolight SENL80FGC4 NG-fired Generator	8760	---	---	0.2	0.8
	Subtotal >	---	---	0.4	---	9.2

Appendix G: Cost Calculations - NOx BACT Analysis

Air Sciences Inc. ENGINEERING CALCULATIONS	PROJECT TITLE: Solvay Package Boiler		BY: T. Martin	
	PROJECT NO: 170-12-2	PAGE: 1	OF: 4	SHEET: SCR1
	SUBJECT: SCR Baseline NOx Control Cost		DATE: August 29, 2012	

I. NOx CONTROL EMISSION REDUCTION

Package Boiler Information			Reference
Boiler Size	254	MMBtu/hour	Manufacturer's specifications (Coen)
Hours of operation	8760	hr/year	

NOx Emission Factors			Reference
Baseline NOx emissions for Solvay boiler	32	ppm at 3% O_2	Coen guarantee based on all current equipment (32 ppm)
configuration with ULNB-LNB	0.038	lb/MMBtu	
SCR controlled NOx emissions	0.010	lb/MMBtu	Lowest NOx Controls from RBLC for boilers with SCR controls

* WAQSR, Chapter 1, Section 3 definition of "standard conditions"; temperature of 68 deg F, pressure reduced to 29.92" Hg at sea level.

Boiler NOx Emission Calculations

Assuming Solvay Boiler Configuration with ULNB-FGR Controls		
Estimated NOx emissions for Solvay	9.7	lb/hr
boiler configuration with ULNB-FGR	42.3	tons/yr

Assuming SCR Controls		
Estimated NOx emissions for SCR	2.5	lb/hr
controlling NOx to 0.010 lb/MMBtu	11.1	tons/yr

Incremental reduction in NOx Emissions from by utilizing SCR controls	31.2	tons/yr

Conversions 2000 lb/ton

Reference Manual: *EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-452-02-001* , January 2002.

Values in blue are input, values in black are calculated.

I. NOx CONTROL EMISSION REDUCTION - CONTINUED

Calculation Assumptions			Reference
Nominal Maximum Heat Input (Q_B)	254	MMBtu/hr, HHV	Manufacturer specifications
Nominal Exhaust Flow Rate ($q_{flue\ gas}$)	135,197	acfm	Manufacturer specifications at 650 deg F
Number of SCR Operating Hours	8,760	hr/yr	Assumed operating schedule
Uncontrolled NOx Emissions (NOx_{in})	0.038	lb/MMBtu, HHV	Existing Solvay Boiler with LNB-FGR
Uncontrolled NOx Emissions	32	ppmvd @ 3% O_2	Manufacturer guarantee, LNB-FGR
Required Controlled NOx Emissions (NOx_{out})	0.010	lb/MMBtu, HHV	SCR Basis, RBLC
Required Controlled NOx Emissions	8	ppmvd @ 3% O_2	SCR Basis, RBLC
Ammonia Slip	2	ppm	Manual, Sec. 4.2, Ch. 2, p. 2-50
Fuel Sulfur Content	0.0007%		Pipeline Quality Natural Gas
ASR	1.05		Manual, Sec. 4.2, Ch. 2, p. 2-50
Store Ammonia Concentration	29%		Manual, Sec. 4.2, Ch. 2, p. 2-50
No. of Days of Storage for Ammonia	14	days	Manual, Sec. 4.2, Ch. 2, p. 2-50
Pressure Drop for Ductwork	3	inches w.g.	Manual, Sec. 4.2, Ch. 2, p. 2-50
Pressure Drop for each Catalyst Layer	1	inch w.g.	Manual, Sec. 4.2, Ch. 2, p. 2-50
Temperature at SCR inlet	650	F	Manual, Sec. 4.2, Ch. 2, p. 2-50
Equipment Life	20	years	Manual, Sec. 4.2, Ch. 2, p. 2-50
Annual Interest Rate	3%		Solvay Estimate
Catalyst Cost, Initial	240	$/ft3	Manual, Sec. 4.2, Ch. 2, p. 2-50
Catalyst Cost, Replacement	290	$/ft3	Manual, Sec. 4.2, Ch. 2, p. 2-50
Electrical Power Cost	0.06	$/kWh	Solvay value for 2012
29% Ammonia Solution Cost	0.101	$/lb	Manual, Sec. 4.2, Ch. 2, p. 2-50
Operating Life of Catalyst	43,800	hr	Assumed 5 year catalyst life
Catalyst Layers	2		Calculated

Calculations

h_{NOx} (NOx removal eff.) $= \dfrac{0.038 - 0.010}{0.038} = 74\%$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.9

$Vol_{catalyst}$ (Catalyst volume) $= 2.81 \times 254.0$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.19

$\times\ [0.2869 + (1.058 \times 0.74)]$ — (h_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.20)

$\times\ [0.8524 + (0.3208 \times 0.038)]$ — (NOx_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.21)

$\times\ [1.2835 - (0.0567 \times 2)]$ — ($Slip_{adj}$; Manual, Sec. 4.2, Ch. 2, Eq. 2.22)

$\times\ [0.9636 + (0.0455 \times 0)]$ — (S_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.23)

$\times\ [15.16 - (0.03937 \times 650) + (2.74E\text{-}05 \times 650\text{^}2)]$ — (T_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.24)

$= 850$ ft3

$A_{catalyst}$ (Cross sectional area of SCR reactor) $= \dfrac{135{,}197}{16 \times 60} = 140.8\ ft^2$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.25

n_{layer} (Catalyst layers) $= \dfrac{850}{3.1 \times 140.8} = 1.9 = 2$ layers — Manual, Sec. 4.2, Ch. 2, Eq. 2.28

h_{layer} (Hgt. of catalyst layer) $= \dfrac{850}{2 \times 140.8} + 1 = 4.0$ ft — Manual, Sec. 4.2, Ch. 2, Eq. 2.29

h_{SCR} (Hgt. of SCR reactor) $= 2 \times (7 + 4.0) + 9 = 31.0$ ft — Manual, Sec. 4.2, Ch. 2, Eq. 2.31

$m_{reagent}$ (Mass flow of reagent) $= \dfrac{0.038\ lb\ NO_x}{MMBtu} \left| \dfrac{254.0\ MMBtu}{hr} \right| 1.05 \left| 74\% \right| \dfrac{17.03\ MW\ NH_3}{46.01\ MW\ NO_x}$

$= 2.8$ lb/hr NH3 — Manual, Sec. 4.2, Ch. 2, Eq. 2.32

m_{sol} (Mass flow of aqueous reagent solution) $= \dfrac{2.8\ lb\text{-}NH_3}{hr} \left| \dfrac{1\ NH_3\ sol}{29\%\ NH_3} \right. = 9.5$ lb/hr — Manual, Sec. 4.2, Ch. 2, Eq. 2.33

II. TOTAL CAPITAL INVESTMENT - DIRECT CAPITAL COSTS

Direct Capital Costs

$DC = Q_B\ [\$3{,}380 + f(h_{SCR}) + f(NH3rate) + f(new) + f(bypass)]*(3500/Q_B)^{0.35} + f(Vol_{catalyst})$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.36

$f(h_{SCR})$ = (6.12 x 31.0) - 187.9 = $2.1 — Manual, Sec. 4.2, Ch. 2, Eq. 2.37

$f(NH3rate)$ = $\frac{(411 \times 9.5)}{254.0} - 47.3$ = -$31.9 — Manual, Sec. 4.2, Ch. 2, Eq. 2.38

$f(new)$ = $0 — Manual, Sec. 4.2, Ch. 2, Eq. 2.39

$f(bypass)$ = $0 — Manual, Sec. 4.2, Ch. 2, Eq. 2.41

$f(Vol_{catalyst})$ = 850 x 240 = $204,000 — Manual, Sec. 4.2, Ch. 2, Eq. 2.43

Scaling Factor = $(3500 / 254.0)^{0.35}$ = 2.50 — Manual, Sec. 4.2, Ch. 2, Eq. 2.36

DC (A) = $2,335,245 — Manual, Sec. 4.2, Ch. 2, Eq. 2.36

III. TOTAL CAPITAL INVESTMENT - INDIRECT CAPITAL COSTS

Indirect Installation Costs — Manual, Sec. 4.2, Ch. 2, Table 2.5

General Facilities		0.05 x A		
Engineering and Home Office		0.10 x A		
Process Contingency		0.05 x A		
Total Indirect Installation Costs (B)		B = A x (0.05 + 0.1 + 0.05)	=	$467,049
Project Contingency		C = (A + B) x 0.15	=	$420,344
Total Plant Cost		D = (A + B + C)	=	$3,222,639
Preproduction Cost		G = D x 0.02	=	$64,453
Inventory Capital	9.5 lb/hr x	0.101 $/lb x 14 days	=	$323

IV. TOTAL CAPITAL INVESTMENT

Total Capital Investment (TCI) — $3,287,415

V. TOTAL ANNUAL INVESTMENT - DIRECT ANNUAL OPERATING COSTS

Annual Maintenance Cost 0.015 x TCI = **$49,311** Manual, Sec. 4.2, Ch. 2, Eq. 2.46

Annual Reagent Cost 83,493 lb/yr sol 0.101 $/lb = **$8,433** See reagent use calc. below

$$m_{reagent\text{-}annual} = \frac{31.2\ \text{ton } NO_{x\,(removed)}}{\text{yr}} \left| \frac{1\ \text{Mol } NH_3}{1\ \text{Mol } NO_x} \right| \frac{17.03\ \text{lb/lb-mol } NH_3}{46.01\ \text{lb/lb-mol } NO_x} \left| \ 1.05 \right. =$$

$$= 12.11\ \text{ton/yr}$$

$$m_{sol\text{-}annual} = \frac{12.11\ \text{ton } NH_3}{\text{yr}} \left| \frac{2000\ \text{lb}}{\text{ton}} \right| \frac{1\ NH_3\ \text{sol}}{29\%\ NH_3} = 83{,}493\ \text{lb/yr } NH_3\ \text{sol}$$

Power Requirements = $0.105\ Q_B\ [NOx_{in}\ h_{NOx} + 0.5\ (P_{duct} + n_{total} \times P_{catalyst})$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48

From ammonia vap. = $0.105\ Q_B\ (NOx_{in}\ h_{NOx}) \times t_{op}$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48 & 2.49

= 0.105 x 254 x 0.038 x 0.74 x 8,760 = 6,542 kWh/yr

=

From pressure drop = $0.105\ Q_B\ (0.5\ (P_{duct} + n_{total} \times P_{catalyst}) \times t_{op}$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48 & 2.49

= 0.105 x 254 x 0.5 x (3 + 2 x 1) x 8,760 = 584,073 kWh/yr

Total Power Loss = 590,615 kWh/yr

Annual Electrical Cost 590,615 kWh/yr x 0.06 $/kWh = **$35,437**

Catalyst Replacement Cost 850 ft^3 x 290 $\$/ft^3$ / 2 layers = $123,303

Manual, Sec. 4.2, Ch. 2, Eq. 2.50

FWF = $i [1/((1 + i)^Y - 1)]$ = 0.188 — Manual, Sec. 4.2, Ch. 2, Eq. 2.52

Future worth factor for catalyst

i = annual interest rate (cost of money) = 3%

Y = $\frac{43,800}{8,760}$ = 5 (rounded to nearest integer) — Manual, Sec. 4.2, Ch. 2, Eq. 2.53

Annual Catalyst Replacement Cost $123,303 x 0.188 = **$23,225** Manual, Sec. 4.2, Ch. 2, Eq. 2.51

Total Direct Annual Cost, DAC **$116,406**

(Annual Maintenance + Reagent + Electrical + Catalyst Replacement Costs)

VI. TOTAL ANNUAL INVESTMENT - INDIRECT ANNUAL OPERATING COSTS

SCR

life (n) = 20 years

cost of money (i) = 3%

CRF = $\frac{i}{(1 - (1 + i)^{-n})}$ = 0.0672 — Manual, Sec. 4.2, Ch. 2, Eq. 2.55

Annual Capital Recovery Cost $3,287,415 x 0.0672 = **$220,966** Manual, Sec. 4.2, Ch. 2, Eq. 2.54

Total Indirect Annual Cost, IDAC (= TCI x CRF) **$220,966**

VII. TOTAL ANNUAL INVESTMENT

Total Annual Cost, TAC = DAC + IDAC **$337,372**

Expected Control Effectiveness ($/ton) $337,372 / 31.2 tons = **$10,830** /ton

Manual, Sec. 4.2, Ch. 2, Eq. 2.58

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC. DENVER • PORTLAND	PROJECT NO: 170-12-2	PAGE: 1	OF: 4	SHEET: SCR2
ENGINEERING CALCULATIONS	SUBJECT: SCR Incremental NOx Control Cost	DATE: August 29, 2012		

I. NOx CONTROL EMISSION REDUCTION

Package Boiler Information			Reference
Boiler Size	254	MMBtu/hour	Manufacturer's specifications (Coen)
Hours of operation	8760	hr/year	

NOx Emission Factors			Reference
Baseline NOx emissions for Solvay boiler	9	ppm at 3% O_2	Coen guarantee based on upgraded ULNB-FGR (9 ppm)
configuration with ULNB-LNB	0.011	lb/MMBtu	
SCR controlled NOx emissions	0.010	lb/MMBtu	Lowest NOx Controls from RBLC for boilers with SCR controls

* WAQSR, Chapter 1, Section 3 definition of "standard conditions"; temperature of 68 deg F, pressure reduced to 29.92" Hg at sea level.

Boiler NOx Emission Calculations

Assuming Solvay Boiler Configuration with ULNB-FGR Controls		
Estimated NOx emissions for Solvay	2.8	lb/hr
boiler configuration with ULNB-FGR	12.2	tons/yr

Assuming SCR Controls		
Estimated NOx emissions for SCR	2.5	lb/hr
controlling NOx to 0.010 lb/MMBtu	11.1	tons/yr

Incremental reduction in NOx Emissions from by utilizing SCR controls	1.1	tons/yr

Conversions 2000 lb/ton

Reference Manual: *EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-452-02-001* , January 2002.

Values in blue are input, values in black are calculated.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler			BY: T. Martin
AIR SCIENCES INC.	PROJECT NO: 170-12-2	PAGE: 2	OF: 4	SHEET: SCR2
ENGINEERING CALCULATIONS	SUBJECT: SCR Incremental NOx Control Cost	DATE: August 29, 2012		

I. NOx CONTROL EMISSION REDUCTION - CONTINUED

Calculation Assumptions			Reference
Nominal Maximum Heat Input (Q_B)	254	MMBtu/hr, HHV	Manufacturer specifications
Nominal Exhaust Flow Rate ($q_{flue\ gas}$)	135,197	acfm	Manufacturer specifications at 650 deg F
Number of SCR Operating Hours	8,760	hr/yr	Assumed operating schedule
Uncontrolled NOx Emissions (NOx_{in})	0.011	lb/MMBtu, HHV	Manufacturer guarantee, ULNB-FGR
Uncontrolled NOx Emissions	9	ppmvd @ 3% O_2	Manufacturer guarantee, ULNB-FGR
Required Controlled NOx Emissions (NOx_{out})	0.010	lb/MMBtu, HHV	SCR Basis, RBLC
Required Controlled NOx Emissions	8	ppmvd @ 3% O_2	SCR Basis, RBLC
Ammonia Slip	2	ppm	Manual, Sec. 4.2, Ch. 2, p. 2-50
Fuel Sulfur Content	0.0007%		Pipeline Quality Natural Gas
ASR	1.05		Manual, Sec. 4.2, Ch. 2, p. 2-50
Store Ammonia Concentration	29%		Manual, Sec. 4.2, Ch. 2, p. 2-50
No. of Days of Storage for Ammonia	14	days	Manual, Sec. 4.2, Ch. 2, p. 2-50
Pressure Drop for Ductwork	3	inches w.g.	Manual, Sec. 4.2, Ch. 2, p. 2-50
Pressure Drop for each Catalyst Layer	1	inch w.g.	Manual, Sec. 4.2, Ch. 2, p. 2-50
Temperature at SCR inlet	650	F	Manual, Sec. 4.2, Ch. 2, p. 2-50
Equipment Life	20	years	Manual, Sec. 4.2, Ch. 2, p. 2-50
Annual Interest Rate	3%		Solvay Estimate
Catalyst Cost, Initial	240	$/ft3	Manual, Sec. 4.2, Ch. 2, p. 2-50
Catalyst Cost, Replacement	290	$/ft3	Manual, Sec. 4.2, Ch. 2, p. 2-50
Electrical Power Cost	0.06	$/kWh	Solvay value for 2012
29% Ammonia Solution Cost	0.101	$/lb	Manual, Sec. 4.2, Ch. 2, p. 2-50
Operating Life of Catalyst	43,800	hr	Assumed 5 year catalyst life
Catalyst Layers	2		Calculated

Calculations

h_{NOx} (NOx removal eff.) $= \dfrac{0.011 - 0.010}{0.011} = 9\%$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.9

$Vol_{catalyst}$ (Catalyst volume) = 2.81 x 254.0 — Manual, Sec. 4.2, Ch. 2, Eq. 2.19
x [0.2869 + (1.058 x 0.09)] — (h_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.20)
x [0.8524 + (0.3208 x 0.011)] — (NOx_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.21)
x [1.2835 - (0.0567 x 2)] — ($Slip_{adj}$; Manual, Sec. 4.2, Ch. 2, Eq. 2.22)
x [0.9636 + (0.0455 x 0)] — (S_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.23)
x [15.16 - (0.03937 x 650) + (2.74E-05 x 650^2)] — (T_{adj}; Manual, Sec. 4.2, Ch. 2, Eq. 2.24)
= 302 ft3

$A_{catalyst}$ (Cross sectional area of SCR reactor) $= \dfrac{135{,}197}{16 \times 60} = 140.8\ ft^2$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.25

n_{layer} (Catalyst layers) $= \dfrac{302}{3.1 \times 140.8} = 0.7 = 2$ layers — Manual, Sec. 4.2, Ch. 2, Eq. 2.28

h_{layer} (Hgt. of catalyst layer) $= \dfrac{302}{2 \times 140.8} + 1 = 2.1$ ft — Manual, Sec. 4.2, Ch. 2, Eq. 2.29

h_{SCR} (Hgt. of SCR reactor) = 2 x (7 + 2.1) + 9 = 27.1 ft — Manual, Sec. 4.2, Ch. 2, Eq. 2.31

$m_{reagent}$ (Mass flow of reagent) $= \dfrac{0.011\ lb\ NO_x}{MMBtu} \times \dfrac{254.0\ MMBtu}{hr} \times 1.05 \times 9\% \times \dfrac{17.03\ MW\ NH_3}{46.01\ MW\ NO_x}$

= 0.1 lb/hr NH3 — Manual, Sec. 4.2, Ch. 2, Eq. 2.32

m_{sol} (Mass flow of aqueous reagent solution) $= \dfrac{0.1\ lb\text{-}NH_3}{hr} \times \dfrac{1\ NH_3\ sol}{29\%\ NH_3} = 0.3$ lb/hr — Manual, Sec. 4.2, Ch. 2, Eq. 2.33

II. TOTAL CAPITAL INVESTMENT - DIRECT CAPITAL COSTS

Direct Capital Costs

$DC = Q_B\ [\$3,380 + f(h_{SCR}) + f(NH3\,rate) + f(new) + f(bypass)]*(3500/Q_B)^{0.35} + f(Vol_{catalyst})$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.36

$f(h_{SCR})$	=	(6.12 x 27.1) - 187.9	= -$21.8	Manual, Sec. 4.2, Ch. 2, Eq. 2.37
$f(NH3\,rate)$	=	$\frac{(411 \text{ x } 0.3)}{254.0}$ - 47.3	= -$46.7	Manual, Sec. 4.2, Ch. 2, Eq. 2.38
$f(new)$	=	$0		Manual, Sec. 4.2, Ch. 2, Eq. 2.39
$f(bypass)$	=	$0		Manual, Sec. 4.2, Ch. 2, Eq. 2.41
$f(Vol_{catalyst})$	=	302 x 240	= $73,000	Manual, Sec. 4.2, Ch. 2, Eq. 2.43
Scaling Factor	=	$(3500 / 254.0)^{0.35}$	= 2.50	Manual, Sec. 4.2, Ch. 2, Eq. 2.36
DC (A)	=	$2,179,636		Manual, Sec. 4.2, Ch. 2, Eq. 2.36

III. TOTAL CAPITAL INVESTMENT - INDIRECT CAPITAL COSTS

Indirect Installation Costs — Manual, Sec. 4.2, Ch. 2, Table 2.5

General Facilities	0.05 x A		
Engineering and Home Office	0.10 x A		
Process Contingency	0.05 x A		
Total Indirect Installation Costs (B)	B = A x (0.05 + 0.1 + 0.05)	=	$435,927
Project Contingency	C = (A + B) x 0.15	=	$392,334
Total Plant Cost	D = (A + B + C)	=	$3,007,897
Preproduction Cost	G = D x 0.02	=	$60,158
Inventory Capital	0.3 lb/hr x 0.101 $/lb x 14 days	=	$12

IV. TOTAL CAPITAL INVESTMENT

Total Capital Investment (TCI) — $3,068,067

V. TOTAL ANNUAL INVESTMENT - DIRECT ANNUAL OPERATING COSTS

Annual Maintenance Cost — 0.015 x TCI = **$46,021** — Manual, Sec. 4.2, Ch. 2, Eq. 2.46

Annual Reagent Cost — 2,982 lb/yr sol × 0.101 $/lb = **$301** — See reagent use calc. below

$$m_{reagent\text{-}annual} = \frac{1.1 \text{ ton } NO_{x\,(removed)}}{yr} \cdot \frac{1 \text{ Mol } NH_3}{1 \text{ Mol } NO_x} \cdot \frac{17.03 \text{ lb/lb-mol } NH_3}{46.01 \text{ lb/lb-mol } NO_x} \cdot 1.05 =$$

$$= 0.43 \text{ ton/yr}$$

$$m_{sol\text{-}annual} = \frac{0.43 \text{ ton } NH_3}{yr} \cdot \frac{2000 \text{ lb}}{ton} \cdot \frac{1 \ NH_3 \text{ sol}}{29\% \ NH_3} = 2{,}982 \text{ lb/yr } NH_3 \text{ sol}$$

Power Requirements = $0.105\ Q_B\ [NOx_{in}\ h_{NOx} + 0.5\ (P_{duct} + n_{total} \text{ x } P_{catalyst})$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48

From ammonia vap. = $0.105\ Q_B\ (NOx_{in}\ h_{NOx}) \text{ x } t_{op}$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48 & 2.49
= 0.105 x 254 x 0.011 x 0.09 x 8,760 = 234 kWh/yr
=

From pressure drop = $0.105\ Q_B\ (0.5\ (P_{duct} + n_{total} \text{ x } P_{catalyst}) \text{ x } t_{op}$ — Manual, Sec. 4.2, Ch. 2, Eq. 2.48 & 2.49
= 0.105 x 254 x 0.5 x (3 + 2 x 1) x 8,760 = 584,073 kWh/yr

Total Power Loss = 584,307 kWh/yr

Annual Electrical Cost — 584,307 kWh/yr x 0.06 $/kWh = **$35,058**

Catalyst Replacement Cost		302 ft^3	x 290 $\$/ft^3$	/ 2 layers	=	$43,847	
							Manual, Sec. 4.2, Ch. 2, Eq. 2.50
FWF	=	$i [1/((1 + i)^Y - 1)]$	=	0.188			Manual, Sec. 4.2, Ch. 2, Eq. 2.52
Future worth factor for catalyst							
i = annual interest rate (cost of money)			=	3%			
Y =	=	$\frac{43,800}{8,760}$	=	5	(rounded to nearest integer)		Manual, Sec. 4.2, Ch. 2, Eq. 2.53
Annual Catalyst Replacement Cost			$43,847	x 0.188	=	**$8,259**	Manual, Sec. 4.2, Ch. 2, Eq. 2.51
<u>Total Direct Annual Cost, DAC</u>						**$89,639**	
(Annual Maintenance + Reagent + Electrical + Catalyst Replacement Costs)							

VI. TOTAL ANNUAL INVESTMENT - INDIRECT ANNUAL OPERATING COSTS

SCR							
life (n)	=	20 years					
cost of money (i)	=	3%					
CRF	=	$\frac{i}{(1 - (1 + i)^{-n})}$	=	0.0672			Manual, Sec. 4.2, Ch. 2, Eq. 2.55
Annual Capital Recovery Cost			$3,068,067	x 0.0672	=	**$206,222**	Manual, Sec. 4.2, Ch. 2, Eq. 2.54
<u>Total Indirect Annual Cost, IDAC (= TCI x CRF)</u>						**$206,222**	

VII. TOTAL ANNUAL INVESTMENT

Total Annual Cost, TAC = DAC + IDAC					**$295,862**	
Expected Control Effectiveness ($/ton)	$295,862	/ 1.1 tons	=	**$265,938** /ton		
						Manual, Sec. 4.2, Ch. 2, Eq. 2.58

I. NOx CONTROL EMISSION REDUCTION

Package Boiler Information			Reference
Boiler Size	254	MMBtu/hour	Manufacturer's specifications (Coen)
Hours of operation	8760	hr/year	

NOx Concentration Conversion Factors			Reference
F-Factor, Fd	8710	dscfm/MMBtu	EPA Reference Method 19, Table 19-2 for Natural Gas
O_2 (% dry), O_2d%	3	%	Manufacturer's specifications (Coen)
Molecular weight of NO_2, MW	46.01	lb/mole	
Molar volume of air at standard conditions, V_M ***	385.3	scf/mole	
NOx conversion factor; 1 ppm NOx =	1.194E-07	lb/dscf at 0% O_2	EPA Reference Method 19, Table 19-1

NOx Emission Factors			Reference
Baseline NOx emissions for current boiler configuration	0.038	lb/MMBtu	Coen guarantee based on all current equipment (32 ppm)
ULNB-FGR Controlled	9	ppm at 3% O_2 *	Manufacturer's guarantee (Coen) for UNLB-FGR controls
NOx emissions	0.011	lb/MMBtu **	

* ppm value assumed to be by volume and under dry conditions

** Emissions in ppm converted to lb/MMBtu using EPA Method 19, Equation 19-1 where:

E (lb/MMBtu) = Cd x Fd x [(20.9/(20.9 - O_2d%)]

Cd = Pollutant Concentration, dry basis, 0% O_2 (lb/dscf)
= emissions in ppm x (NOx ppm to lb/dscf conversion factor)
(the lb/dscf conversion factor is the molecular weight of pollutant, MW, in lb/mole divided by the molar volume of air, V_M, in scf/mole).

Fd = F-Factor, volume of combustion components per unit of heat content

%O_2d = Concentration of O_2 in Exhaust Gas, %

*** WAQSR, Chapter 1, Section 3 definition of "standard conditions"; temperature of 68 deg F, pressure reduced to 29.92" Hg at sea level.

Boiler NOx Emission Calculations

Assuming Current Boiler Configuration		
Estimated NOx emissions for current	9.7	lb/hr
boiler configuration:	42.3	tons/yr
Assuming ULNB-FGR Controls		
Estimated NOx emissions for ULNB-FGR	2.8	lb/hr
controlling NOx to 9 ppm:	12.2	tons/yr
Reduction in NOx Emissions utilizing ULNB-FGR	30.0	tons/yr

Conversions	2000	lb/ton
	0.7457	kW/hp

Reference Manual: *EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-452-02-001* , January 2002.

Values in blue are input, values in black are calculated.

II. TOTAL CAPITAL INVESTMENT - DIRECT CAPITAL COSTS

Purchased Equipment Costs

Base Cost for ULNB-FGR Burner Hardware	$750,000 for	254 MMBTU/hr ULNB-FGR		
Ref. Coen proposal to Solvay dated March 30, 2012				
Adjustment to base cost for burner hardware (operational controls and burner parts to install existing boiler with no changes to NOx controls.)	-$190,000	Solvay provided to R. Steen, Air Sciences on April 2, 2012		
			Factor	**Totals**
Cost of ULNB-FGR Equipment	$560,000	1 unit	A	$560,000
Instrumentation			10% A	$56,000
WY Sales taxes, per Solvay			6% A	$33,600
Freight			5% A	$28,000
Purchased Equipment Cost, PEC			21% A=B1	$677,600
No in-house modification and development costs; Solvay does not expect to make modifications to the burner			B2	$0
Installation Cost for New ULNB-FGR Ref. Estimate from D. Hansen, Solvay based on typical project experience at Solvay (Increased costs for ducting, electrical, foundations)	$168,000	one time charge	30% x A = B3	$168,000
Total Direct Capital Cost, DCC			B=B1+B2+B3	**$845,600**

III. TOTAL CAPITAL INVESTMENT - INDIRECT CAPITAL COSTS

Indirect Installation Costs (applied to PEC only and not In-House Modification and Development or Direct Installation costs)

General Facilities	5% x B1	$33,880
Engineering and Home Office Fees	10% x B1	$67,760
Process Contingencies	5% x B1	$33,880
Indirect lost production costs; Assume no lost production costs to bring new boiler online	B4	$0
Total Indirect Installation and Lost Production Costs	20% x(B1)+B4=C	**$135,520**
Project Contingency	15% x(B+C)=D	$147,168
Total Plant Cost	B+C+D=E	**$1,128,288**
Allowance for Funds During Construction	F	$0
Royalty Allowance	G	$0
Preproduction Cost	2% x(E+F)=H	$22,566

IV. TOTAL CAPITAL INVESTMENT

Total Capital Investment, TCI	**$1,150,854**

V. ANNUALIZED COST RECOVERY FACTOR

ULNB-FGR

life (n)	=	25 yrs			
cost of money (i)	=	3%			Ref. Solvay estimate/assumption
1 + I	=	1.03			
CRF	=	$\frac{i}{(1-(1+i)^{\wedge -n})}$	=	0.0574	Manual, Sec. 4.2, Ch. 2, Eq. 2.55.

Lifetime of a complete ULNB-FGR replacement for boiler is assumed 25 years per Coen.

VI. TOTAL ANNUAL INVESTMENT - DIRECT ANNUAL OPERATING COSTS

						Totals
Operating Labor						
Operator	NOT ESTIMATED - Assumed negligible per EPA Cost Control Manual					$0
Supervisor	NOT ESTIMATED - Assumed negligible per EPA Cost Control Manual					$0
Annual Maintenance	$20,000	every	1	years		$20,000

Ref. Estimate from D. Hansen, Solvay
increased maintenance for larger HP fan and controls.

Utilities

Electricity

Annual Electricity Cost = Power x Cost of Electricity x Total Operating Time		$74,469
Increase in fan power for new fan	200 hp	
Price of electricity in 2012	$0.06 per kWh in 2012	
Fan operational schedule	24 hr/day	
	365 day/yr	
	8760 hr/yr	
Annual capacity factor	0.95	

Total Direct Annual Cost, DAC — **$94,469**

VII. TOTAL ANNUAL INVESTMENT - INDIRECT ANNUAL OPERATING COSTS

IDAC = CRF x TCI — $66,091

Total Indirect Annual Cost, IDAC — **$66,091**

VIII. TOTAL ANNUAL INVESTMENT

Total Annual Cost, TAC = DAC + IDAC — **$160,560**

Expected Control Effectiveness ($/ton) — **$5,345**

Appendix H: GHG BACT Analysis Report

AIR SCIENCES INC.

DENVER • PORTLAND

August 9, 2012

Project No. 170-12-2

Mr. Donald J. Law
US Environmental Protection Agency, Region 8 Air Program
1595 Wynkoop Street
Denver, CO 80202-1129

Subject: Solvay Natural Gas Boiler Addition

Dear Mr. Law:

Solvay Soda Ash JV, Green River Soda Ash Plant (Solvay) submits the attached BACT analysis of greenhouse gas emissions for its proposed installation of a 254 MMBtu/hour natural gas fueled boiler. The boiler is to be installed at the existing Solvay facility, which is located 20 miles west of Green River, Wyoming, in Sweetwater County. The criteria pollutant application is to be submitted separately to Wyoming Department of Environmental Quality (DEQ) in the near future. While this component of the application is being submitted earlier than the criteria component, we understand your intent and Solvay encourages EPA and DEQ to combine the review and public comment of the full application.

Three copies of this report are attached, with a copy also being sent to Wyoming Department of Environmental Quality. Please contact Tim Brown of Solvay (307-872-6570) or Rodger Steen of Air Sciences Inc. (303-807-8024) with any questions you might have on this analysis.

Sincerely,

Rodger G. Steen

Rodger G. Steen
Principal

Attachment

Cc: Tim Brown – Solvay
David Hansen - Solvay
Andrew Keyfauver – Wyoming DEQ

1301 WASHINGTON AVENUE, SUITE 200
GOLDEN, COLORADO 80401
303·988·2960 FAX 303·988·2968

AIR SCIENCES INC.

DENVER ▲ PORTLAND

PSD Permit Modification Natural Gas Boiler Addition Greenhouse Gas BACT

PREPARED FOR:

SOLVAY SODA ASH JOINT VENTURE
GREEN RIVER SODA ASH PLANT

PROJECT NO. 170-12
AUGUST 2012

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Tables

Figures

Appendices

LIST OF ABBREVIATIONS

ACFM	Actual Cubic Feet per Minute
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
BLM	Bureau of Land Management
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	Continuous Emission Monitor
CFR	Code of Federal Regulations
CH4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
DEQ	Wyoming Department of Environmental Quality
EGU	Electric Generation Unit
EPA	The United States Environmental Protection Agency
°f	Degrees Fahrenheit
FGR	Flue Gas Re-circulation
FR	Federal Register
ft	Feet
g	Gram
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
H_2O	Water
hr	Hour
kWh	Kilowatt-hour
lb.	Pound
lb./hr	Pounds per Hour
μ	Micro (10^{-6})
MCR	Manufacturer Capacity Rating
MMBtu	Million British Thermal Units
MT	Metric Tons or Tonnes
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NO_X	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review

O_3	Ozone
OFA	Over-Fire Air
PAE	Projected Actual Emissions
PFC	Perfluorocarbon
PM_{10}	Particulate Matter (with aerodynamic diameter ≤ 10 micron)
ppb	Parts per Billion
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psig	pounds per square inch - gauge
PTE	Potential to Emit
RBLC	RACT BACT LEAR Clearinghouse
RH	Relative Humidity
s	Second
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
tpy	Tons per Year
ULNB	Ultra-Low-NO_X Burner
VOC	Volatile Organic Compound
WAAQS	Wyoming Ambient Air Quality Standards
WI	Water Injection
yr	Year

1.0 INTRODUCTION

Solvay Soda Ash Joint Venture Inc. (Solvay), located 20 miles west of Green River, Wyoming, plans to de-bottleneck its soda ash and related products production circuits. This primarily involves adding a steam boiler, which will be the only new source of air emissions. The de-bottlenecking will include adding a heat exchanger, which will utilize available steam heat for the purpose of speeding up the crystallization processes. The combination will serve to increase both short-term and long-term production while remaining within the previously permitted design rates.

The additional boiler will trigger a PSD-level modification to Solvay's air permit, and as one component of that permitting application, the greenhouse gas (GHG) emissions and related Best Available Control Technologies (BACT) are addressed in this report. The PSD permit application is being prepared for submittal to the Wyoming Department of Environmental Quality (WDEQ). Since Wyoming has not accepted authority for administering the federal PSD rules related to GHGs (40 CFR 52.21), the GHG part of the application, is to be processed by the United States Environmental Protection Agency (U.S. EPA) and is prepared in this separate document for submittal to the U.S. EPA.

Figure 1 shows the Solvay Soda Ash Plant location. Figure 2 provides an aerial photograph of the plant, showing the proposed boiler location, which is to be within the existing physical building perimeter. General information regarding the project and project-relevant contacts is provided below. Table 1 lists the equipment to be added to the plant as part of this proposed action. This listing shows that this will be a simple modification of adding a steam boiler to an existing steam manifold and distribution system and a clear liquor heater which will be a consumer of steam heat with no air emissions.

Project Name:
Natural Gas Boiler Addition – 2012

Applicant, Owner, and Operator:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant

Physical Location:
NE Quarter, Section 31, Township 18 North, Range 109 West
Sweetwater County, Wyoming

Mailing Address:
Solvay Soda Ash Joint Venture
P. O. Box 1167
Green River, WY 82935

Contact Information:

Responsible Official:	Mr. Ronald O. Hughes	307-875-6500
Permit Contact:	Mr. Tim Brown	307-875-6500

Table 1. Equipment to be Added as Part of Project

Equipment Unit	Type of Emission
Natural Gas-Fueled Boiler	Combustion Emissions
Clear Liquor Pre-Heater	None

Figure 1. Solvay Facility Location on a Regional Scale Map

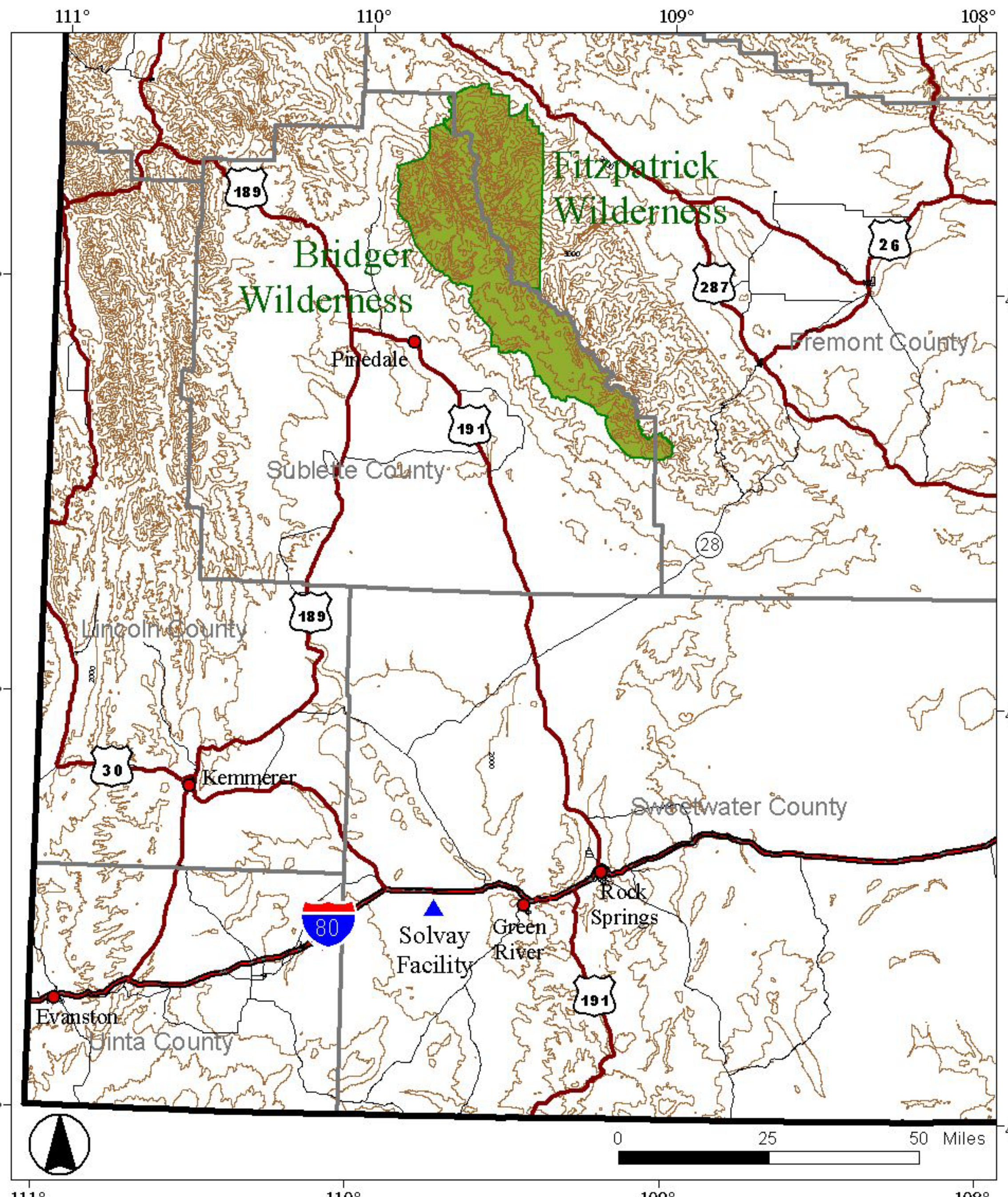

Figure 2. Facility Aerial Photo

Although separately reviewed, the BACT for the criteria pollutants and the BACT for the GHGs must be considered together because one affects the other. The pollutants of interest in the criteria pollutant BACT are primarily nitrogen oxides (NO_X), and secondarily carbon monoxide (CO). Both can have health and environmental effects, so they are important to control. This BACT is for the purpose of minimizing GHGs that have global warming effects. Thus, there needs to be a balance in engineering design to address both criteria pollutant and GHG emissions. Fortunately, to a degree, good design benefits both.

The March 2011 U.S. EPA Guidance (Guidance)[1] for permitting GHG sources is followed for this analysis, and a listing of specific boiler CO_2e (carbon dioxide equivalent) improvements (ICI Boiler Manual)[2] is also largely followed for the BACT recommendation.

[1] U. S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, EPA-457/B-11-001.

[2] U. S. EPA, Office of Air and Radiation, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, October 2010.

2.0 DESCRIPTION OF THE SOURCE

The Solvay natural gas boiler will add steam-generating capacity to the two existing coal-fueled boilers so that Solvay will have flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel between coal and natural gas. The clear liquor preheater will use steam heat to increase the temperature of the clear liquors (with product in solution) upstream of the crystallizers, thereby increasing the evaporation rates and speed of crystallization.

With this de-bottlenecking, Solvay expects to increase annual soda ash production by approximately 14 percent. Steam production is also expected to increase by approximately 14 percent as the two are nearly directly related, but steam production will still be limited to below boiler capacity as there is currently no other host for additional steam consumption. Although steam production will be limited by current soda ash capacity, this permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package boiler (a Foster Wheeler Model AG 5195, 254 MMBtu boiler) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers, increasing plant steam production capacity by 33 percent. As part of the 2003 purchase of the American Soda plant, Solvay owns this boiler. The Foster Wheeler boiler specifications are provided in Appendix A.

Short-term production capacity will not change, although the addition of the heat exchanger will allow short-term actual production to increase and come nearer to capacity. On an annual basis, this additional steam production will enable the plant to continue production during boiler maintenance so there can also be an increase in long-term actual production. Solvay anticipates actual annual soda ash production to increase by 360,000 tons from the current actual level of 2.55 to 2.91 million tons. Depending on the mix of boiler use between coal and gas, the group of boilers' criteria pollutant, and CO_2e, emissions could increase, but not necessarily, as the gas boiler emissions are lower on a per-unit-of-steam-basis than those from the coal boilers. If the gas boiler were to operate at capacity with the coal boilers cut back, boiler emissions of at least NO_x and CO_2e would decrease. Emissions from the other existing fueled sources, which are the calciners and some dryers, could increase with increased production since they operate in series with the steam-heated crystallizers.

The criteria pollutant BACT analysis for the additional boiler concludes that an ultra-low NO_X burner (ULNB) with associated 30 percent flue gas recirculation (FGR) and combustion control instrumentation will be required to minimize NO_X and CO emissions with a guarantee of 9 ppm NO_X and 50 ppm CO (See

Appendix B, Coen Burner bid). The associated instrumentation will include a continuous emission monitor for NO_X and a diluent. Thermal efficiency of this boiler in its initial configuration was estimated by Foster Wheeler at 83.3 percent, shown on page 3 of Appendix A. This compares favorably with the ICI Boiler Manual listing of current-technology natural gas boiler efficiency at 84 percent. Both the initial Foster Wheeler configuration and the ICI Manual configuration assume about 10 percent flue gas recirculation and higher NOx and CO emissions than Solvay is presently proposing. The presently proposed ULNB is associated with up to 30 percent FGR and this higher recirculation has a slight negative effect on thermal efficiency. Solvay's proposed Coen burner with 30 percent FGR is associated with 15 percent excess air, and the IGI Boiler Manual[3] states that with increased excess air over 10 percent, there is a decrease in thermal efficiency. Using the values provided with this statement and assuming a linear relationship of thermal efficiency with excess air, there will be about a one third of a percent efficiency loss due to the ULNB and its related extremely low CO and NOx emissions. So, the currently proposed Solvay boiler configuration will have a thermal efficiency of about 83 percent. Solvay believes that this burner modification and associated combustion control instrumentation represent the design and operational controls of a current-technology boiler with high levels of emission control. Since the boiler is already owned by Solvay and it represents current technology, the cost of replacing the boiler would be high and therefore alternate boiler and burner designs are not considered further in this BACT analysis. The remaining GHG BACT analysis is limited in its focus on efficient heat use and retention.

There will be no alteration of electrical switching and metering, and therefore no emissions of SF_6.

The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant. So, there will be no installation of a fuel feed line, except within the plant. Solvay will regulate the gas down to approximately 73 psig for plant-wide purposes and further regulate at the burner according to burner manufacturer specifications. If the boiler were to run at 100 percent Manufacturer Capacity Rating (MCR) of 254 MMBtu/hr for 365 days/yr., annual natural gas consumption would be 2,181,412,000 scf/yr or 101,138,000 lb/yr. using a value of 22,000 BTU/lb., or 1020 Btu/SCF as the HHV of natural gas.

Gas piping for the boiler will add 6 valves and 18 flanges[4] in the main service (3 and 4 inches in diameter). There will be no additional fuel-line heaters associated with this boiler installation. Methane emissions from these valves and flanges are estimated using EPA emission factors[5] and these CO_2e emissions are very small in comparison to those from the boiler combustion.

Construction will involve a minimal amount of site preparation since the boiler will be installed within the existing facility, as shown in Figure 2. There will be no additional land clearing or road building. Preparation for the boiler will consist of excavation for the foundation, drilling of caissons, and

[3] IGI Boiler Manual, page 12, Paragraph 5

[4] E-mail from Ryan Schmidt to Tim Brown, June 12, 2012, Subject Valves and flanges

[5] Per 40 CFR 98, Subpart W, Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production). Western U.S., Population Emission Factors - All Components, Gas Service; assume all gas emitted as methane to be conservative.

foundation pouring. The boiler will be trucked from Colorado on state highways to Solvay and temporarily stored on site until the foundation is prepared, then placed in final position. Mechanical an electrical work will proceed from there. The foundation excavation is scheduled to begin in the second quarter of 2014 and the project will be completed in the fourth quarter of 2014.

3.0 APPLICABILITY OF PSD REGULATIONS AND TRIGGERING BACT ANALYSIS FOR GHG

The New Source Review analysis for criteria pollutants is performed under Wyoming Air Regulations, (WAQSR) Chapter 6, Section 4 and an application for a PSD permit modification is being submitted to the Wyoming Department of Environmental Quality. That application (the associated emission tables are also provided here in Appendix C) shows that criteria pollutant emissions (NOx, CO, VOCs, and PM) will trigger the PSD New Source Review (NSR) process. The inventory of increased emissions associated with the criteria pollutant application and GHG are calculated on a common spreadsheet so that all operational assumptions are common. Appendix D contains the GHG emissions portion of the spreadsheet and the final column of the third table shows an increase in CO_2e emissions of over 75,000 tons per year. Thus, Under 40 CFR 52.21 (b)(49)(iv)(b) this project is also subject to the federal New Source Review for GHG.

When estimating CO_2e emissions and according to 40CFR 52.21 (b)(49)(ii)(a), six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are to be considered, and their GWP is to be estimated according to (ii)(a). The Appendix D emissions estimates are performed accordingly. Because the natural gas boiler combusts sulfur- and fluoride-free fuel, there will be essentially no emissions of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride so the analysis is limited to estimation of emissions of the first 3 substances.

There are no ambient (or impact) standards for GHGs, and therefore the NSR is limited to control technology review, which in turn consists of a BACT analysis and addressing any New Source Performance Standards (NSPS), found in 40 CFR Part 60, requirements. There are no NSPS promulgated for GHG, although one has been proposed on March 27, 2012 for electric generating units (EGUs), to be described as NSPS Subpart TTTT.

Although not applicable because none of its product is electricity sold to the electric grid, the proposed standard will be equal to or below 1000 lbs. CO_2 / MWh. It is estimated as the sum of all emissions divided by the sum of all electrical and useful thermal energy (CHP) over a 12-month rolling period. None of the Solvay boiler steam is to be used for electricity generation, some of it is to be used for mechanical power drives, but most of it is to be used as heat for an industrial process. Thus, a comparison with this standard can only be hypothetical. An estimate of thermal efficiency is provided here for conversion to electricity at 33 percent and 35 percent[6]. The current potential to emit (PTE) estimate of CO_2 shown in Appendix D is 130,049 tons with a heat input of 2,225,000 MMBtu/yr. (652,000 MWh/yr. energy equivalent). Converting to useable energy output at 33 and 35 percent, the output would be 215,139 MWh and 228,178 MWh respectively. So the CO_2 emissions per unit of energy output would be 1090 lbs./MWh and 1028 lbs./MWh at 33 percent and 35 percent electric production efficiency

[6] http://www.naturalgas.org/overview/uses_eletrical.asp . Typical thermal efficiency range given as 33 to 35 percent.. and ICI Boiler Manual: page 35, given as a typical thermal efficiency for steam boiler

respectively. These emission rates are about 9 percent and 3 percent higher than the proposed NSPS for EGUs.

For the purpose of determining the trigger for a BACT analysis, the Guidance is followed. The first step, from the Guidance Appendix, is to define the source category, which is "a modified source, with the permit to be issued after July 11, 2011", so Appendix D contains the appropriate flow chart. From the existing Solvay Title V permit, it is apparent that the existing source has a PTE of greater than 100,000 tons per year (tpy) of CO_2e and GHG mass greater than 250 tpy. Baseline actual emissions (BAE) of the regulated pollutants and GHG constituents are estimated using the actual emissions between 2006 and 2010 for a CO_2e total of 1,167,598 tpy. Projected actual emissions (PAE) are a combination of emissions from the natural gas boiler operating at capacity, and the existing sources producing an additional 360,000 tpy of product. Appendix D of this report provides the calculations of BAE and PAE for CO_2 and CO_2e.

The explanation of how the emission baseline actual inventories were selected is fully explained in the criteria pollutant BACT analysis, but an abbreviated explanation is provided here. BAE are defined in WAQSR, Chapter 6, Section 4(a) and 40 CFR 52.21 (b)(48)(ii) for an existing emissions unit. BAE means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit PSD application is received by WDEQ, whichever is earlier. For a regulated PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated PSD pollutant. To calculate BAE for the existing project sources, Solvay utilized the latest available five years (2006 to 2010) of facility-wide actual emissions information. For GHG, the period 2007 and 2008 was selected because these years represented the highest BAE from 2006 to 2010.

PAE are defined in WAQSR, Chapter 6, Section 4(a) and 40 CFR 52.21(b)(41)(i) in the federal PSD regulations for both new and existing units and means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated PSD pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project. In lieu of calculating PAE, the emissions for a unit may be calculated as the PTE for the unit. Solvay has the flexibility of operating the boiler at its MCR so its PAE is based on capacity operation. The existing sources PAE is evaluated at a production increase of 360,000 tons per year of product.

The analysis for GHG contributors is different from the analysis for the criteria pollutants only in that the emissions from the "contemporaneous changes" are not addressed for the GHGs. This is because the baseline GHGs are not defined and their contribution will only add a minor amount of emissions, which will not affect the major GHG source categorization. Table 2 shows that this modification will have GHG global warming potential (GWP) emissions of at least 130,000 tpy, well over the 75,000 tpy threshold, and the GHG mass of emissions will be greater than zero. The netting, considering the gas boiler (including valve and connector fugitives) and debottlenecked process and combustion emissions, is estimated, as shown in Appendix D, and the results are provided in Table 3. The mass of GHG will be greater than zero and the CO_2e will be greater than 75,000 tpy. Consequently, following the Guideline Appendix D flowchart, this modification will be a major GHG source and subject to GHG BACT.

Table 2. Boiler Greenhouse Gas Annual Emissions*

Component	Mass Emission (tons/yr)	GHG GWP (multiplier)	GHG CO_2e (tons/yr)
CO_2	130,041	1	130,041
N_2O	0.25	310	76
CH_4	6.97	21	146
HFCs & PFCs	0	various	0
SF_6	0	23,900	0
Total	130,049		130,263

* Gas-fueled boiler operating at design rate for 8,760 hours per year and including fugitive emissions from valves and connectors.

Table 3. Net Solvay Plant Increase in Greenhouse Gas Annual Emissions with Additional Boiler and Associated Existing Unit Use Increases *

Component	Mass Emission (tons/yr)	GHG GWP (multiplier)	GHG CO_2e (tons/yr)
CO_2	493,305	1	493,305
N2O	1.3	310	402
CH4	14.7	21	309
HFCs & PFCs	0	various	0
SF6	0	23,900	0
Total	493,321		494,015

* Gas-fueled boiler operating at design rate for 8,760 hours per year and including fugitive emissions from valves and connectors.

4.0 BACT SELECTION PROCESS

Section III of the Guidline for permitting of GHG is followed here for the BACT analysis. The scope of this permitting effort and BACT analysis is limited to the one used-gas-fueled boiler added to an existing facility, since the only equipment change regarding air emissions is the added boiler. The five-step process is followed and addresses only GHG emissions. Since the boiler will be natural-gas-fueled, the overwhelming pollutant of interest is CO_2. There will be negligible emissions of the other GHGs. Of the negligible GHG constituents, only methane and nitrous oxide are generally recognized as constituents of natural gas combustion so these are also quantified.

Natural gas is essentially methane with small quantities of the higher carbon chain hydrocarbons (ethane, propane, butane, etc.) and is the cleanest burning hydrocarbon fuel, especially with regard to GHG emissions, so consideration of alternate fuels to decrease GHG emissions is irrelevant in this BACT analysis. Furthermore, because of the high level of excess air (15 percent) associated with the proposed NOx and CO BACT controls, burner fuel slip is virtually eliminated. If there were to be any incomplete combustion, it would be sensed by the CO CEM used to track compliance with the anticipated CO emission limit. This BACT analysis is reduced to one of minimizing fuel consumption per unit of useable heat produced. Stated another way, this analysis focuses on maximizing the thermal efficiency of the boiler and its associated equipment and minimizing heat loss as waste.

Appendix F of the Guidance is referenced as it provides an example BACT analysis for a 250 MMBtu/hr gas-fueled boiler. This BACT process generally follows the process designed for the criteria pollutants, but for GHG minimization, the process for this boiler becomes an efficiency-improvement process, layered on top of a NO_X/CO BACT evaluation. The technologies discussed below are related to energy efficiency improvements and associated energy, environmental, and economic impacts.

The BACT analysis is a five-step process:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

4.1 Step 1: Identify all available control technologies

Solvay proposes to add steam-generating capacity to an existing steam manifold and consumption system using an existing, owned, and available boiler; therefore, use of any other heat-generating equipment and processes would fundamentally redefine the proposed source. Because of this, no alternate means of generating additional steam are considered.

The gas-fueled boiler is being added to the Solvay plant to supplement the steam provided by existing coal-fueled boilers, but it could also be used as a base load while varying the steam production of the coal-fueled boilers to meet capacity. In this way, the CO_2e would be reduced because the GWP per unit of heat from coal is higher than the CO_2e for heat from natural gas (94 kg CO_2/MMBtu v 53 kg CO_2/MMBtu[7]). Solvay asserts that the flexibility to use the boilers as best meets the needs of the plant is its choice and that the BACT analysis does not extend to this level of controlling the mix of boiler usage.

Technology related to maximizing steam boiler energy efficiency is provided in the ICI Boiler Manual, which addresses feasible efficiency-increase technologies as a surrogate for CO_2 control technologies for steam boilers. At 254 MMBtu per hour, the Solvay boiler fits well within the class of ICI boilers addressed. Table 4 lists the entries as feasible options for maximizing energy efficiency. As Table 4 illustrates, the methods of increasing thermal efficiency from a boiler can be grouped as: 1) Efficient design of boiler and associated steam delivery equipment, 2) Efficient operation of equipment, 3) Good maintenance, and 4) Other measures.

[7] Ibid.

Table 4. **Possible Energy Efficiency Improving Methods, Feasibility, and Whether Included as BACT**

Method	Feasible?	Reason	Included as BACT?	Reason
Efficient design of boiler and associated steam delivery equipment				
High-efficiency burner	Yes		Yes	New Coen Ultra-Low NO_X Burner (ULNB) to be added
Refractory material selection	Yes		Yes	Best available already included with boiler[8]
Use of an economizer	Yes		Yes	Economizer comes with boiler package. Used to heat boiler feed water. Economizer reduces exhaust to 320°F
Blowdown heat recovery	Yes		Yes	Blowdown (steam with high solids content) is sent to the flash tank where 300 lb steam flashes to 35 lb steam and condensate
Condensate recovery for boiler reuse	Yes		Yes	Maximum amount the steam circuit will accept based on water quality requirements. All condensate is recovered for use in the plant
Combustion air pre-heater	Yes		Yes	Combustion air is drawn from the process building roof line which is approximately 20 F warmer than building ground level air, and also serves as crude air conditioning by drawing into the building cooler ambient air
Increase the amount of boiler insulation	Yes		Yes	Boiler designed for 3”, feasibility decreases with thickness. Solvay agrees to install at 4 inches. See Appendix E
Increase the amount of refractory lining	No	A boiler performance function. Meets current design requirements[9]		
Efficient operation of the boiler and related steam distribution equipment				
Energy management systems – use and production of steam	Yes		Yes	Boiler will be connected into the current steam management system and will be controlled by Solvay’s current energy management system
Good O&M practices – tuning, oxygen trim/cleaning of burner and oxygen feeds	Yes		Yes	Written O&M practices includes these

[8] Telecom, Tony Hawranko of Foster Wheeler with Ryan Schmidt of Solvay, May 8th, 2012. Available changes in refractory material would make negligible difference in heat transfer.
[9] Ibid. Increase in amount of refractory material would require boiler redesign.

Method	Feasible?	Reason	Included as BACT?	Reason
Boiler instrumentation & controls	Yes		Yes	The boiler package includes I&C. Additional control is included with ULNB to meet NO_X & CO emission limits
Good maintenance				
Steam-line maintenance (including integrity of insulation)	Yes		Yes	Scaling to be controlled with anti-scalant additive. Pipes to be visually checked at least quarterly and insulation replaced as needed
Minimization of air infiltration	No	Positive pressure boiler		
Minimization of gas-side heat transfer surface deposits	No	Not relevant to gas firing		
Minimize steam trap leaks	Yes		Yes	Inspected and repaired at least annually
Other Measures				
Turbine shaft power extracted from high-pressure steam	Yes		Yes	Included in existing steam circuit. There are 9 turbines powering 4 ducted fans and 5 pumps. With more continuous steam supply and less production “down time,” turbines will be used more continuously over the year. Turbines eliminate use of electrical power
Carbon Sequestration	No	Sinks Not Available	No	Unreasonable cost

4.2 Step 2: Eliminate technically infeasible options

The last of the "Other Measures" options is Carbon Capture and Storage (sequestration) (CCS) is addressed first. It is discussed in the Guideline as an add-on control technology and should be considered for:

> *....facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).* [10]

Since the Solvay Green River Facility is not one of these types of facilities, and furthermore, is relatively small at 254 MMBtu/hr., the Guideline states that CCS is expected to be not feasible as an available control option. Nevertheless, EPA requested that Solvay provide an evaluation of the economic feasibility of CCS as part of Step 4 of the natural gas boiler addition BACT analysis.

All the Table 4 methods are feasible except those related to multiple fuel burning, boiler/burner design, and CCS. Slag formation and cleaning of surface deposits are related only to coal combustion, so they are not addressed for this boiler since it will be natural-gas fueled. The quantity and placement of refractory material is part of the boiler design and determined by the manufacturer for this boiler and should not be altered. The ultra-low NO_X burner (ULNB) package includes combustion monitoring and controls; it comes with a CO and NO_X emission guarantee. The ULNB package likely serves to maximize the boiler thermal efficiency, but it cannot be altered for GHG purposes without voiding the guarantee.

The Report of the Interagency Task Force on Carbon Capture and Storage (Task Force Report)[11] lists an application of CCS at the Searles Valley Minerals soda ash plant in Trona, California. It is used as part of the process and CO_2 is consumed on site unlike Solvay where the natural soda ash process converts trona ore (sodium sesquicarbonate dihydrate [Na_2CO_3-$NaHCO_3$-$2H_2O$]) to soda ash (Na_2CO_3) giving off CO_2 and H_2O in the decomposition process. The Solvay Green River Facility process does not require the addition of CO_2 to convert sodium bicarbonate ($NaHCO_3$) in a brine solution into soda ash as is needed in the Searles Valley process[12]. Therefore it is not feasible as a component of the Solvay process.

4.3 Steps 3 & 4: Rank remaining control technologies and evaluate most effective controls

Regarding selection of a high efficiency boiler as part of the GHG BACT process, since Solvay already owns the boiler, as part of the purchase of another soda ash plant in 2004; the boiler is available at no cost

[10] Guidance, page 32, paragraph 2.

[11] Report of the Interagency Task Force on Carbon Capture and Storage, http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf, p 31.

[12] Garrett, Donald E., Natural Soda Occurrences, Processing, and Use, Copyright 1992 by Van Nostrand Reinhold

to Solvay. Furthermore, in comparing the Solvay boiler thermal efficiency, discussed in Section 2.0, Description of the Source, with typical new boilers, the Solvay boiler is similar in efficiency, and is already owned, so without further cost analyses, it is obvious that cost of other designs would be large and there is no need to further evaluate other designs.

Solvay is implementing all of the feasible methods of efficiency improvement. In addition to enclosing the boiler within a building, which will provide protection from the wind and extreme winter temperatures, the amount of exterior boiler insulation is addressed. The thickness of insulation is evaluated as a balance between emission-control-effectiveness and practicality.

The boiler manufacturer recommends a minimum of 3 inches of insulation based on safety considerations and has designed the boiler, including its valves, fittings and sleeves, for 3 inches of insulation. With greater insulation thickness the access to and maintenance from the exterior becomes more difficult. Moreover, the volume into which this boiler is to be installed is limited and insulation thickness will consume volume needed for movement around the boiler. Solvay has priced the cost of 3, 4, 5, and 6 inches of insulation, using a 20-year remaining life of boiler, natural gas cost savings of $2.34 per thousand cubic feet, and 8760 hours per year operation at 254 MMBtu/hr (which is at PTE). These costs are summarized in Table 5 and the calculations and assumptions are provided in Appendix E. The analysis indicates that the cost to Solvay of installing insulation spread evenly over 20 years, and including fuel savings from additional insulation is about neutral, considering the cost savings of boiler fuel all the way to 6 inches of insulation. Thus, from this simplistic analysis it makes economic sense to install more insulation and there is no natural limit. But as insulation increases, so do issues with buried valves, fittings, and sleeves, and the inconvenience of maintenance is not a quantifiable cost. Solvay proposes to use the diminishing benefit in avoided CO_2e value with thickness to establish a BACT limit. An increase from 3 to 4 inches is associated with a 10.4 tpy benefit in avoided CO2e emissions, and carries a benefit of $257 per year. An increase from 4 to 5 inches is associated with a 6.5 tpy decrease in CO2e, which is 0.005 percent of the 130,000 tons per year total potential to emit (PTE) and essentially a negligible decrease. Insulation increase to 6 inches is associated with an even smaller CO_2e benefit. Since the boiler will never operate at PTE but insulation cost is fixed, the actual benefit should be lower. Solvay believes that improvements in CO_2e beyond 4 inches of insulation are essentially negligible and therefore, not worth the additional maintenance difficulties and loss of volume surrounding the boiler. Therefore, Solvay proposes 4 inches of insulation as BACT.

Table 5. Incremental costs for added boiler insulation

	Increase 3″ to 4″	Increase 4″ to 5″	Increase 5″ to 6″	Increase 3″ to 6″
Decrease in CO_2e	10.4 tons/yr	6.5 tons/yr	4.4 tons/yr	21.3 tons/yr
Increase in insulation cost	$3,036	$9,994	$3.036	$16,066
Annualized cost of insulation and fuel savings at PTE	- $257/yr	$146/yr	- $51/yr	- $192/yr
Cost of CO_2e eliminated, fuel savings included	- $25/ton-yr	$ 23/ton-yr	- $12/ton-yr	- $9/ton-yr

Review of the cost for CCS: For this analysis Solvay relies primarily on the Task Force report, prepared by 14 Executive Departments and Federal Agencies.

From that report, the cost for CCS is segmented into:

1) Cost of capture and compression of the CO_2,

2) Transport of the CO_2 and

3) Storage in geologic formations.

This analysis is approximate and addresses only the costs for capture and compression since it is the bulk of the CCS cost[13]. Furthermore, the bulk of their cost data is from coal-fueled power plants, likely because there is a higher concentration of CO_2 in the flue gas than for natural gas[14], 13 to 15 percent for coal compared to 3 to 4 percent for natural gas, and it is more efficient to capture a constituent from a higher concentration flue gas. Nevertheless, without attaching an increase in cost on a per unit of CO_2 controlled basis, the cost for retrofit of a capture system and compression will be higher for natural gas fueling than for coal fueling of the boiler. From figure III-I[15], the cost of the cost of CO_2 removal in a retrofit, post-construction circumstance, such as for Solvay, but for a coal-fueled boiler is listed at $103 per tonne[16] ($94 per ton). Since the Solvay boiler is smaller and gas fueled (CO_2 per unit of heat is much lower) the avoided cost per tonne of CO_2 removal will be much higher than $103 per tonne. Although not

13 Task Force Report, p 27, Section III , "Approximately 70–90 percent of that cost is associated with capture and compression."

14 Task Force Report, p 29, "A high volume of gas must be treated because the CO_2 is dilute (13 to 15 percent by volume in coal-fired systems, three to four percent in natural-gas-fired systems"

15 Task Force Report, p 34, right end, green bar

16 The Federal GHG Reporting Rule requires annual emissions to be reported in metric tons (MT) or tonnes.

quantified, it is likely to be an avoided cost well above $114 per tonne ($104 per ton) CO_2 captured, which is the highest avoided cost of all configurations of power plants. The cost for retrofit of CCS is therefore considered by Solvay to be an unreasonably high cost and therefore it is eliminated as a BACT option.

4.4 Step 5: Select BACT

Solvay commits to installation or incorporation of the listed efficiency enhancements provided in Table 4 as included in the GHG BACT requirements, including use of 4 inches of boiler insulation.

5.0 PROPOSED CO_2e EMISSIONS LIMITS FOR COMPLIANCE DEMONSTRATION

The maximum annual CO_2e emissions are proposed to be the emissions using the boiler Manufacturer Capacity Rating (MCR) which is 254 MMBtu/hr, boiler operation for 365 days/yr., and nominal natural gas quality emissions provided by EPA in 40 CFR Part 98, Subpart C, Table C-1. That nominal value is a CO_2e emission factor of 117 lb/MMBtu. This estimation calculation is shown in Appendix D of this report and results in an annual emission limit of 130,263 tons per year (118,173 MT per year)

The short-term (hourly) CO_2e limit will be in the form of a mass of CO_2e per unit of energy input to the boiler and is derived from a consideration of the variability in fuel constituents. Pipeline gas is primarily composed of methane, but can have varying percentages of the hydrocarbon constituents (methane, ethane, propane, butane, pentane and hexane, etc) and also varying percentages of CO_2 among other passive constituents. The boiler manufacturer provided an estimate of the maximum heat content pipeline fuel that the boiler could experience in NW Colorado and this fuel analysis is presented on page 2 of Appendix A. The CO_2 emissions associated with this gas composition are estimated on the final page of Appendix D, using the constituent-specific CO_2 emissions per unit mass of the constituent and assembling these according to the quantity of the constituent in that fuel analysis. The CH_4 and N_2O components in the exhaust are expected to be approximately the same as for nominal natural gas and these fixed factors are added to the measured CO_2 to determine the total CO_2e short-term emission limit. These factors are 0.05 and 0.07 lb/MMBtu respectively. The CO_2 measurement will be by CEM for exhaust concentration and associated with a continuously measured flow rate using Equation C-6 of 40 CFR Part 98.33 (a)(4)(ii). The Solvay short-term limit by this method is 125.3 lb CO_2e per MMBtu heat input. This is 7 percent higher than the nominal pipeline natural gas value of 116.9 lb CO_2e per MMBtu.

For purposes of demonstrating compliance on a short-term basis, a boiler heat input is needed. This will come from measurement of the volume of fuel consumed by the boiler and coupling it with a Solvay-monitored heat content. Thus, there are three independent measurements being made using different plant control systems, CO_2 concentration, and exhaust flow rate from emissions monitoring, and boiler heat input from process controls. Solvay believes that the shortest time interval over which this will be a meaningful calculation would be 24 hours, using hourly averaged or totaled measurements. Hourly calculations would likely contain inconsistencies because all the measurements would not have been collected at the same time, but more importantly, Solvay expects some hysteresis in the furnace response to fuel feed and probably also with the CO_2 and flow rate monitors, so that the three may not track hour by hour. Therefore Solvay requests that the short-term CO_2 measurement be tracked on a 24-hour totalized basis. The estimate of CO_2e emissions per unit of heat input will be calculated and compared with the compliance limit every calendar day.

6.0 SUGGESTED BACT COMPLIANCE DEMONSTRATION

Solvay proposes the following demonstrations of the proposed BACT commitments:

1) Agreement to include with the boiler installation:

   - ULNB
   - Boiler insulation at 4 inches
   - In-stack economizer to preheat boiler water
   - Blowdown flash tank
   - Ducting for combustion air to be drawn from process building roof line
   - Integration of this boiler into the existing steam production system in parallel with the coal-fueled boilers
   - CO_2 monitoring with CEM

2) Agreement to incorporate into its maintenance and operations practices:

   - Maximized condensate recovery
   - Scheduled inspections of steam lines
   - Use of an anti-scalant agent in the boiler water

3) Demonstration of good operating and maintenance practices by meeting the CO and NO_X emission limits: this is to be a separate requirement of the air permit, and demonstration does not need to be duplicated for the GHG BACT.

4) The long and short-term emission limits for CO_2e emissions will be constructed as discussed in Section 5. Proposed limits are 130,263 tons per year (118,173 tonnes per year), and 125.3 lb per MMBtu, (HHV) respectively.

7.0 ENDANGERED SPECIES ACT AND NATIONAL HISTORIC PRESERVATION ACT (SHPO) DISCUSSIONS

A US Fish and Wildlife Service consultation on threatened and endangered species report and listing for this project is provided in Appendix F. The entire Solvay project will be contained within the existing facility and therefore there should be no additional impact to threatened and endangered species.

Solvay's existing species protection includes a waterfowl protection plan, not included here, but available upon request. They abide by the Avian Protection Plan (APP) Guidelines that were prepared by the Edison Electric Institute's Avian Power Line Interaction Committee (APLIC) and The U.S. Fish and Wildlife Service (USFWS).

Per discussions in a June 18, 2012 meeting between USEPA and Solvay, Solvay has performed a survey to determine the nearest sites listed in the National Register of Historic Places relative to the Solvay facility. The National Park Service (NPS) provides a spatial mapping coverage of historic properties listed in the National Register which can be overlaid on Google Earth™ maps.[17] Figure 3 is a map of the nearest historic properties to the Solvay facility based on this NPS dataset. The nearest historic property to the Solvay facility is a property referred to as Granger Station which is located approximately 20 kilometers to the northwest of the facility. In addition, there is a historic property located further to the north (29 kilometers from Solvay) and there are three properties located to the east in the town of Green River (24 kilometers Solvay).

With the installation of this natural gas boiler, there are no anticipated social or economic impacts beyond the plant site. Air quality impacts to these properties will be well below the primary or secondary NAAQS and should have no effect on them.

[17] National Park Service webpage: http://nrhp.focus.nps.gov/natreg/docs/Download.html#spatial

Figure 3. Map of Historic Places in the Vicinity of the Solvay Facility

Appendix A: Foster Wheeler Boiler Specifications

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**		Equipment No.: **81-BO-001 / 002**
Operating and Design Conditions		
Minimum Boiler Design Parameters		
Steam Flow	-Capacity, lb/hr, each	200,000 lb/hr
	-Temperature, °F	435
	-Pressure, psig	350
Blowdown		6450 lb/hr ⚠1
Automatic Turndown Required		25% ⚠1
Return Condensate	-Flow, lb/hr ⚠1	200,000
	-Temperature, °F	199
Makeup Water	-Flow, lb/h	6450 ⚠1
	-Temperature, °F	199 ⚠1
	-Pressure, psig	25
	-Analysis	
	-Total dissolved solids	Negligible ⚠1
	-Hardness	0 ⚠1
	-Conductivity	
	-Silica	Negligible ⚠1
	-Free or combined CO_2	
Stack Emissions Design Parameters		
	-Maximum allowable NO_x	0.035 Lbs / MMBTU (HHV) ⚠2
	-Maximum allowable CO	100 ppm

Note to the Bidder:
Bidder is requested to confirm the data filled in the right hand column and fill in any blank lines as completely as possible.
Please type or print and stay within the lined area.

(The information provided in these data pages (1-5) is to be considered preliminary and subject to final contract review)

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**		
Operating and Design Conditions (cont'd.)			
Equipment Location	Indoors at Elev. 6600 FASL		
Duty	Continuous		
Natural Gas (At various heating values supplied)	Lowest	Highest	Intermediate
Gross-Heating value, BTU/scf		1064.1	
-Net heating value, BTU/scf		961.0	
(dry basis @ 14.73 psia & 60 °F)			
-Specific gravity (dry basis)		0.61	
-Composition, Volume %			
-Carbon dioxide		2.47	
-Nitrogen		0.61	
-Methane		90.45	
-Ethane		4.07	
-Propane		1.39	
-Iso Butane		0.24	
-Normal Butane		0.27	
-Iso Pentane		0.13	
-Normal Pentane		0.10	
-Hexane		0.24	
-Helium		0.03	
-Sulfur (gr./100 scf)			

Note to the Bidder:
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EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001/ 002**	
Number-required/operating/standby	2/2/0	
Vendor	Foster Wheeler 1	
Manufacturer	Foster Wheeler 1	
Model No.	AG-5195 1	
Manufacturer Location	St. Catharines, Ontario 1	
Heat Input (Max), MMBTU/hr 2	250 1	
System Performance	100% condensate	100% make up
Hot Water Flow -Capacity, lbs./hr.	215,000 1	215,000 1
-Temperature, °F	240 1	240 1
-Pressure, psig	395 1	395 1
Turndown Capacity	10:1	
Efficiency (Predicted) 2	83.2921 2	
Utility requirements		
-Electrical, kW/V-ph-Hz		
-Plant air, scfm @ psig		
-Instrument air, scfm @ psig		
-Low pressure steam, lb/hr @ psig		
-Cooling water, gpm @ °F		
-Natural gas, lb/hr @ psig 2	11,384 (based on 0% blowdown) 2	
-Natural gas, mm BTU/hr.,	249.8 2	
Flue gas		
-Volume, acfm	80,115 1	
-Temperature, °F	320 1	
-Composition:		
O_2, %	2.827 1	
Co_2, %	13.591 1	
H_2O, %	11.581 1	
N_2, %	72.000 1	

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Boiler	Equipment No.: 81-BO-001 / 002
-Type	"D" Type Model AG-5195
-Steam drum size	54" ID, 39' Length
-Mud drum size	24" ID, 39' Length
-Material of water tubes	SA-178
-Diameter of tubes/wall thickness	2½" / 0.135" and 2" / 0.105" △2
-Overall dimensions, ft.-in.	LxWxH – 48' x 13'-4" x 17'-9"
-Wt of boiler, lbs	180,000
-Total effective heating surface, ft^2 △2	16,490 △2
-Furnace volume, cu ft	3375 △1
Boiler Burner	
-Manufacturer/Model	Coen Company / DAF △3
-No. of Burners/Capacity per burner	1 x 208,500 lb/hr
-Description	
Boiler Combustion Air Fan	Equipment No.: 81-FN-031 / 032
-Manufacturer	Howden Fans △1
-Model	1085BA97 △1
-Capacity, acfm @ in. H_2O	88,141 @ 27.68" WC
-Material casing and wheel	
-Motor hp	600 △2
Economizer	Equipment No.: 81-HR-001 / 002
-Water capacity, lbs/hr	208,500
-Water inlet temperature, °F	240
-Water outlet temperature, °F	339
-Pressure drop, psi	6
-Effective heating surface, ft^2	16,484 △1

Note to the Bidder:
Bidder is requested to fill in the right hand column
as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Deaerator	Equipment No.: 81-DE-001/002
-Manufacturer/Model No.	Kansas City Deaerator ⚠1
-Size of Tank	8'-6" Diameter, 21' Length
-Materials/thickness, in.	0.25
-Operating conditions -Pressure, psig	10
-Temperature, °F	240
-Design conditions -Pressure, psig	30
-Temperature, °F	410
-Residual O_2 in effluent, mg/l	0.005
-Steam flow, Lb/h	17,000
Boiler Feedwater Pumps	Equipment Nos.: 81-PP-098A thru C
-Manufacturer/Model No.	Carver / WKM-80 ⚠1
-Capacity and pressure, gpm @ psig	245,000 lb/hr @ 500 psi ⚠3
-Materials of Construction	D.I. / C.I. ⚠1
-Motor hp	250
Boiler Stack	One stack per boiler
-Diameter & Height, feet ⚠2	5'-9 3/4" Diameter, 50-ft overall
-Materials of Construction	Carbon Steel
-Nozzles Provided	Two (2) 4" flanged sampling ports
Chemical Injection Package	Equipment No.: 81-WT-007/008/009/010
-Manufacturer/Model No.	Neptune ⚠1
-Size of Tank	200 gallons each
-Materials/thickness, in.	316SS ⚠1
-Chemicals Used	Sulfite, Phosphate
-Pump Capacity & Pressure	12 gal/hr ⚠3

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

Appendix B: Coen Burner Bid

From: **Wieszczyk, Wayne** <wwieszczyk@coen.com>
Date: Fri, May 4, 2012 at 11:34 AM
Subject: RE: Solvay project: Further questions regarding 9ppm burner; Coen #201202-24271-A
To: "Schmidt, Ryan" <ryan.schmidt@solvay.com>
Cc: North Associates <northassociates@yahoo.com>, "Ingvarson, Lyall" <lyall.ingvarson@coen.com>

Ryan,

Coen is pleased to offer the following information per your request.

1) Coen can offer 50 PPM CO along with the 9 PPM NOx at 100% MCR with 30% FGR and 15% EA. The CO will be guaranteed from 25-100% MCR. The only condition we would be concerned with is that the boiler furnace wall should be seal-welded to help assure no CO bypassing. If the wall is not sealed, Coen would recommend a CO test port at the rear of the furnace to allow us to confirm the CO at the rear vs. the stack during start-up if this became an issue.

2) The products of combustion are listed below based on 100% MCR (253.77 mmbtu/hr) and 30% FGR and 15$% excess air.

Combustion Products

	vol%, wet	vol%, dry	scfm	mass%, wet	mass%, dry	lb/hr	MW
CO_2	8.53%	10.19%	4352	13.43%	15.01%	29755	44.0
H_2O	16.36%		8351	10.55%		23374	18.0
O_2	2.51%	**3.00%**	1279	2.87%	3.21%	6359	32.0
N_2	71.75%	85.79%	36622	71.93%	80.41%	159378	28.0
Ar	0.86%	1.02%	437	1.22%	1.37%	2713	39.9
SO_2	0.00%	0.00%	0	0.00%	0.00%	0	44.0

1) The following estimated temperate per your request for NG

ADFT of NG = 3,391 deg F

Flue Gas Temperature downstream of the economizer = 350 deg F

Flue Gas Temperature in the stack = ~350 deg F

If you need any further information, please feel free to contact us anytime.

Regards,

Wayne A. Wieszczyk

Sr. Application Engineer

Boiler Burner Group

Coen Company Inc.

2151 River Plaza Dr, Suite 200

Sacramento, CA 95833

Coen® Ultra Low NOx Burner Package to meet 9 PPM (Coen File D-13384-1-000)

SUBMITTED TO

Mr. Mike Ganskop
Solvay Chemicals

FOR

Solvay Chemicals
Green River, Wyoming

Proposal Number:	201202-24271-A R1
Application Engineer:	Wayne A. Wieszczyk
Tel:	1 (530) 668-2128
Email:	wayne.wieszczyk@coen.com
Date Prepared:	March 30, 2012

PROPOSAL CONTENTS

1.0 Overview

Rev. 1 Revise proposal for Ultra Low NOx burner option to meet 9 PPM NOx.

Solvay Chemicals has requested Coen® to supply option for changing the existing low NOx DAF™ burner to Ultra Low NOx burner. Coen has over 400 ULN burner installations using the RMB™ family of burners to meet single digit NOx. The RMB™ will require 30% FGR to achieve 9 PPM. Coen is offering a budget price including a new FD fan package, the new trains along with Fyr-Monitor™ BMS/CCS PLC based systems to assure the controls match the performance desired for Ultra Low NOx operation.

2.0 Burner Design Basis & Specifications

2.1 Boiler Information

Number of boilers	1
Number of burners per boiler	1
Boiler manufacturer	Foster Wheeler
Boiler designation	AG-5195
Furnace dimensions: Width inside (feet)	7.08'
Height (feet)	13.71'
Length (feet)	36.75'
Length for flame (feet)	31.75'
Steam capacity (lb/hr)	208,562
Design boiler HHV BTU input (mmbtu/hr) NG	253.77
Boiler furnace pressure at proposed conditions ("w.c.)	18.51
Steam pressure (psig)	350
Steam temperature (°F)	SAT
Boiler Feedwater temperature (°F)	236
Boiler efficiency Natural Gas	---
Maximum boiler stack height (feet)	35-40
Location	Indoor
Economizer used	Yes

2.2 Electrical & Utilities

Fan electrical characteristics (v/hz/ph)	480/60/3
Panel electrical characteristics (v/hz/ph)	120/60/1
Instrument air supply (clean, dry, and oil-free)	100 psig

2.3 Codes

Area classification	Non-Hazardous
NEMA class rating	NEMA 4
Code requirements	NFPA 85
Piping requirements	Coen Standard
Insurance requirements	None

2.4 Combustion Air

Combustion air temperature (°F)	80
Air humidity (%)	50
Air density at standard conditions (lbm/ft^3)	0.075
Mix density with FGR/Combustion air (lbm/ft^3)	0.0512
Mix Temperature FGR/combustion air	145
Plant elevation (FASL)	6.250
Combustion air pre-heat	No

2.5 Fuels

Main gas fuel .... NG
Ignition fuel .... Natural Gas

NG Gas Details:
Higher heating value (btu/scf) 1,064
Specific gravity 0.61

2.6 Burner Performance

Burner pressure drop ("w.c.) 10.0
Burner excess air 15
FGR percent 30
Boiler turndown based on steam output: 6:1
NG regulated supply pressure required at train inlet (psig) 40
N.Gas Pilot gas pressure required (psig) 1.0

2.7 Burner Estimated Emissions

Fuel: NG
NOx (ppm, ref 3% O2) 9
CO (ppm, ref 3% O2) 123

Notes:
1. Emission guarantees are from 25-100% MCR for NG.
2. Emission guarantees based on HHV.
3. Coen will guarantee the stack CO emission to be less than 123 PPM provided furnace leakage does not contribute any CO to the total CO emissions. This guarantee is based on; 1) operating with 15% excess air at high fire; 2) 31.75 ft (min) furnace length to the superheater; 3) the boiler meeting the minimum construction requirements for furnace side wall construction and seals at the front wall and drum and 4) the customer providing sampling port for measuring the CO emissions.

2.8 Paint and Finish
Coen surface preparation and painting will be as follows:

Product
- Acrylic Emulsion primer/finish, no topcoat
- Sherwin-Williams DTM Acrylic or equivalent
- SW data sheet 1.21

Surface Preparation
- SSPC-SP6

Dry Film Thickness (S-W, other mfg see product sheet)
- 5.0 - 6.0 mils

Performance
- Consult the manufacturer's product information sheet

Technique
- Consult the manufacturer's application bulletin and JZ 9001-OPS-MFG-58

Inspection
- Consult JZ 9001-OPS-QC-61

3.0 Scope of Supply

3.1 Burner Equipment

The following is included as part of Coen's offering:

Windbox, Damper (Qty: 1)

The windbox houses the burner and is constructed of carbon steel and has insulation to reduce the surface temperature due to the FGR and combustion air mixture. The windbox is to be seal welded to the boiler front plate and is of sufficient size to provide air cooling to a major portion of the boiler front plate.

A jackshaft control drive system is mounted on the windbox front and includes:

- Purge and low fire position switches
- Ball bearing pillow blocks, self aligning, and permanently lubricated
- Mechanical linkage constructed from 1/2" pipe with heavy duty, aircraft type ends to eliminate backlash.
- Jackshaft, 1-3/16 solid round stock

The jackshaft must be driven by an actuator and will be linked to the following components:

- Windbox damper

A combustion air damper is mounted on windbox. The damper is a slow opening, multibladed, streamline design. It is designed to have a relatively straight line characteristic in respect to air flow versus damper positions. The maximum air leakage will not exceed 10% in the closed position.

Jackshaft Actuator (Qty: 1)

The jackshaft actuator is mounted on the windbox and is electrically driven. The actuator with smart positioner accepts a 4-20 mA control input signal and drives all items linked to jackshaft.

FD Fan-FGR Package (Qty: 1)

Coen will be supplying a new FD fan package to deliver the combustion air and Induce 30% FGR to the new RMB Ultra Low NOx burner. The following is included:

- FD Fan package with 800 HP TEFC motor 4160 V/3PH/60HZ, IVC damper with actuator with smart I/P positioner. Note fan will be shipped partial-assembled.
- FGR inlet box with manual damper.
- 38"D FGR x 12"D connection as part of the FGR inlet box.
- Inlet silencer with piezometer with loose DP transmitter & integral manifold valve (field installed).
- FGR damper, 38"D with actuator and I/P positioner and position feedback – shipped loose.
- FGR thermal mass flow meter with 4-20 mA output – shipped loose

RMB Burner (Qty: 1)

The RMB includes the following sub-assemblies:

- One (1) primary (inner) register with integral gas injectors and air flow swirl vanes
- One (1) secondary (outer) register with integral gas injectors and air flow vanes
- One (1) set of pre-cast refractory quarl segments that comprise of the inner zone throat.
- Two (2) manual gas butterfly valves
- Two (2) gas pressure gauges c/w isolation cocks
- One (1) burner front hub assembly, complete with two observation ports and flame scanner swivel mounts
- One (1) burner guide ring for the purpose of centering the burner in the windbox

Natural Gas Pilot (Qty: 1)

The pilot is electrically ignited and is interruptible per NFPA Class III requirements. The pilot electrode is sparked by a 6000 Volt transformer.

Natural Gas Pilot Train (Qty: 1)

Pilot train, fully assembled and mounted and wired to a junction box on the windbox with the following components:

- One inlet manual shutoff valve, bronze body.
- One strainer, 100 mesh, cast iron body.
- One pressure regulating valve, aluminum body.
- Two safety shutoff valves aluminum body.
- Two safety shutoff valve leak test valves.
- One vent valve, aluminum body.
- One manual shutoff valve, bronze body.
- One pressure gage, 4-1/2”.
- One flex hose, stainless steel.

Natural Gas Train (Qty: 1)

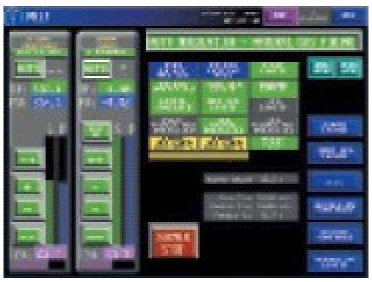
The main gas train is assembled and mounted on the windbox. Portion (*) of the train will be assembled and shipped loose for field installation, support, wiring, etc. The following components are included:

- *One manual shutoff valve, cast iron body, Homestead.
- *One strainer, cast iron body.
- *One pressure regulating valve, cast iron body, Fisher.
- *One supply pressure gauge, 4-1/2" Ashcroft.
- *One flow meter with 4-20mA output signal
- One low pressure switch, Ashcroft.
- Two safety shutoff valves each with a proof of closure switch, cast iron body, Maxon CC-5000.
- Two safety shutoff valve leak test valves.
- One vent valve, cast iron body, Maxon.
- One vent manual test valve, bronze body.
- One manual shutoff valve, cast iron body.
- One high pressure switch, Ashcroft.
- One Main pneumatic flow control valve, 125# FF cast iron body, with smart I/P positioner, mechanical down stop and low fire switch.
- Two burner pressure gauges, 4-1/2" Ashcroft.

<u>Fyr-Monitor BMS and CCS (Metering) Control Panel</u> (Qty: 1)

Fyr-Monitor touchscreen control system which will have burner management system (BMS) and combustion controls system (CCS) in the same panel and will use same touchscreen. The CCS type is Metering with fully-metered cross limiting, O2 trim, FGR trim, 3-Element Feedwater and Draft controls. Two PLCs will be used, one for BMS and one for CCS. The touchscreen will be a 10.4" CTC color screen and will have the following control screens.

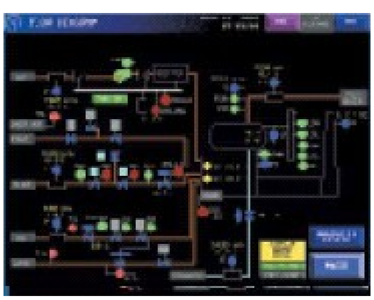
(Rainhood not included)



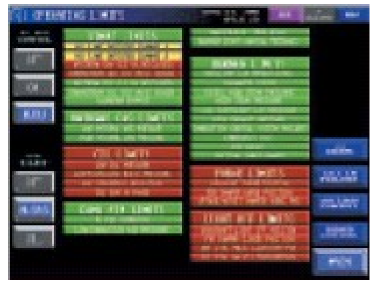
Main
Opening screen which shows control loops and pertinent BMS information for starting and monitoring burner.

Navigator
Provides access to other screens except system setup screens

Surface Clean Allows screen cleaning without changing control settings

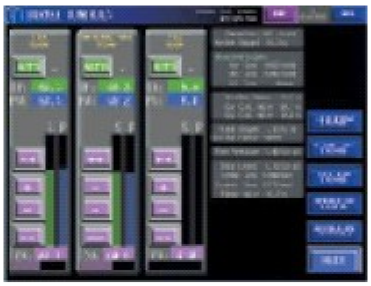


Flow Diagram
Piping style diagram of whole boiler process with numerical readouts of measured process values and showing valves open or closed, etc.



Alarm Status
Displays current alarm conditions in an annunciator style layout.

Alarm History Logs most recent alarm conditions.



Burner Control
Detailed information about all the control loops in the system.

Trending
Trends of all process variables controlled by the Fyr Monitor. Note, data is not stored, just shown for about 30 minutes of operation.

Two Allen Bradley PLCs will be mounted in a panel which will house all the necessary I/O modules, relays, terminals, etc. The following is included:

- (2) Allen Bradley CompactLogix PLC with all required I/O modules
- CTC touchscreen panel with 256 colors and TFT (active matrix) LCD.
  - Size: 10.4”
- Memory: 8 megabyte flash ROM, 8 megabyte RAM
- The above items mounted in Nema 4X enclosure 48” x 36” x 24

Scanner system is as follows:

Coen system consisting of the following equipment:

Scanner Model: (2) Fireye scanners
Note: Scanner(s) require cooling/purge air.

<u>Loose pressure limits included</u>: (Qty: 1 ea)
- One Excess Steam pressure switch
- One High Furnace pressure switch
- One Low Combustion Air flow switch
- One Low Purge Air flow switch
- One Low Instrument Air pressure switch

3.2 Items Not Included In our Proposal- Existing

- Remove, disposal, demolition etc of existing equipment to allow for new equipment.
- Installation of new equipment
- Removal of windbox, DAF burner and throat
- Modification to the boiler front wall (as required) including all material and installation for the new RMB throat.
- Pipe, fittings, ducting, gaskets, wire and conduit as required for installation of valves, dampers and Fyr-Monitor panels
- Boiler drum level probes
- Boiler auxiliary drum level cut-out switch
- New FD fan package foundation
- New FD fan outlet duct including expansion joint to connect FD fan outlet to the
- New windbox damper inlet connection
- New FD Fan inlet supports (as required to support inlet silencer/FGR box).
- New FGR ducting, expansion joint, supports, connectors, etc.
- New FD Fan motor starter or VFD
- Any Pressure safety switches not listed above for BMS interface per NFPA-85
- Reuse Feedwater controls and instruments
- Reuse Draft controls
- O2 analyzer
- Source of ignitor/scanner cooling/purge air
- All insulation and lagging
- Erection
- Start-up Service
- Freight

4.0 Price

Budget: One RMB ULN unit as detailed below will be
SEVEN HUNDRED & FIFTY THOUSHAND DOLLARS ....**$750,000.00**.
The following equipment changes from the Base offering to be included.

Price Validity: Above prices are valid for acceptance by May 1, 2012 for delivery within 30 weeks of receipt of order unless otherwise specified. See Schedule section, below, for estimated lead times.

Prices do not include taxes. Freight cost is not included in our price. Equipment will be shipped Ex-works. point of manufacture, freight collect.

5.0 Payment

Subject to credit approval, progress payments will be required according to the following schedule: Net 30 days

15% of total order upon issuance of the purchase order or contract
30% on drawing transmittal
45% six (6) weeks after drawing transmittal
10% upon notice of availability of shipment

ed beyond thirty (30) days from the contractual delivery date due to no fault of Coen and when such delay has caused an increase in the cost of the goods or services to Coen. Escalation charges shall be based upon either: (1) the Producer Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics for Finished Goods, Capital Equipment only, or (2) the U.S. Department of Labor, Employment Cost Index (ECI), Private Industry, Table 3. Employment Cost Index for total compensation for private industry workers, by industry and occupational group; Manufacturing Industry, as applicable. The base line for calculating the adjustment shall be the date of the contract.

6.0 Drawing and Schedule

Drawings will be submitted eight (8) weeks after receipt of purchase order and all engineering information. Shipment will be fourteen (14) weeks from receipt of approved drawings. Note: Actual dates will be confirmed upon receipt of the purchase order and scheduling meeting completed.

The following drawings/documents will be submitted for approval:

General Arrangement Drawing - Windbox-burner-trains
General Arrangement Drawing - Burner
Flow Diagram
Fyr-Monitor BMS/CCS Enclosure and Wiring Schematic
Fyr-Monitor BMS Sequence of Operation
Fyr-Monitor CCS Controls Narrative
Bill of Materials
IOM manual

7.0 Clarifications and Exceptions to the Specifications

None received. Coen standard scope, design, material and fabrication to be supplied

8.0 Terms & Conditions of Sale

This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes and does not constitute a commitment or offer to sell goods or services at the prices and terms referenced herein. Any firm offer or binding quotation will be the subject of a formal proposal at a future date.

To the extent an order is issued by you and accepted by Coen, then the resulting contract documents shall be subject to the attached Coen Company, Inc. Standard Terms and Conditions of Sale (the “T&Cs”) and this proposal (including, without limitation, the T&Cs) shall be incorporated by reference into such contract documents. In the case of a conflict among the contract documents, then the terms of the proposal (including, without limitation, the T&Cs) shall take precedence.

This proposal document is confidential and intended solely for the use of the individual or entity to which it is addressed. If you have received this proposal in error, please contact the sender and destroy all copies of the original message.

Regards,

Wayne A. Wieszczyk
Sr. Application Engineer
Boiler Burner Group
Coen Company Inc.
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Appendix C: Criteria Pollutant Emission Inventory

PSD APPLICABILITY SUMMARIES

Emissions Changes: Project Only, No Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
Baseline Actual Emissions (BAE) for Project	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	8.0	1,165,771	1,167,598
New Boiler Emissions (PTE = PAE) >	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (PAE) >	224.7	224.7	224.7	503.3	5955.0	4.4	1873.7	0.028	9.6	1,529,044	1,531,350
Projected Actual Emissions (PAE) for Project	233.0	233.0	233.0	515.5	6022.8	5.0	1879.7	0.029	9.6	1,659,093	1,661,614
Project Emissions Increase	50.2	50.2	50.2	101.4	1591.5	0.8	438.6	0.005	1.6	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Is the Project Emissions Increase Significant?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

Net Emissions Changes: Includes Both Project and Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
New Boiler Emissions (Project)	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (Project)	41.9	41.9	41.9	89.1	1523.7	0.1	432.6	0.005	1.6	363,273	363,752
Project Subtotal >	50.2	50.2	50.2	101.4	1591.5	0.8	438.6	0.005	1.6	493,321	494,015
New Contemporaneous Sources	22.1	22.1	22.1	37.5	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Increases	7.2	7.2	7.2	1.1	0	N/A	0	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Decreases	-0.1	-0.1	-0.1	0	0	N/A	0	N/A	N/A	0	0
Contemporaneous Subtotal >	29.2	29.2	29.2	38.6	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Sum of Project and Contemporaneous Emissions	79.4	79.4	79.4	140.0	1620.8	N/A	447.8	N/A	N/A	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Trigger PSD?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

* The increase in GHG emissions from the project (i.e., new boiler and debottlenecked sources) is significant and there are no creditable contemporaneous decreases of GHG. Thus, project clearly triggers PSD for GHG (BACT for the new boiler applies regardless) and no further quantification is performed.

Blue values are input values and black are calculated values.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 2	OF: 5	SHEET: Applicability
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: July 2, 2012		

AIR SCIENCES INC.

DENVER • PORTLAND

SUMMARY OF BASELINE ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	New Package Boiler	New	0	0	0	0	0	0	0	0	0	0
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	0.0	0.0	0.0	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	8.6	8.6	8.6	0	0	0	0	0	117,265	117,265
16	Dryer Area	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	61.4	61.4	61.4	268.5	1252.6	4.2	1236.1	0.0225	372,352	373,965
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	10.3	10.3	10.3	5.1	528.7	0	71.4	0.0001	76,128	76,157
50	"C" Train Dryer Area	Debottlenecked	2.9	2.9	2.9	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	3.7	3.7	3.7	35.7	178.7	0	1.1	0.0002	153,323	153,363
52	Product Silo - Top #2	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	0.8	0.8	0.8	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.4	10.4	10.4	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.6	3.6	3.6	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	32.0	32.0	32.0	46.6	2444.1	0	131.4	0.0004	275,796	275,899
81	"D" Train Dryer Area	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	10.6	10.6	10.6	58.2	27.2	0	1.1	0.0002	170,906	170,949
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.2	0.2	0.2	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	1,165,771	1,167,598

SUMMARY OF BASELINE ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	0.2	0	N/A	0	N/A
35	Sulfite Dryer	Existing	3.24	3.24	3.24	3.24	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0.13	0.13	0.13	0.13	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0.13	0.13	0.13	0.13	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0.13	0.13	0.13	0.13	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0.01	0.01	0.01	0.01	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0.02	0.02	0.02	0.02	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	0.06	0.06	0.06	0.06	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0.02	0.02	0.02	0.02	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0	0	0	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	0.08	0.08	0.08	0.08	0	N/A	0	N/A
105	S-300 Dryer #1	New	0	0	0	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0	0	0	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	0	0	0	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0	0	0	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	0	0	N/A	0	N/A
E4	GM 8.1L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
E5	GM 4.3L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	0	0	N/A	0	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0	0	0	0	0	N/A	0	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0	0	0	0	0	N/A	0	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0	0	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	0	0	N/A	0	N/A
		Total >	3.8	3.8	3.8	4.0	0	N/A	0	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary.

AIR SCIENCES INC. DENVER • PORTLAND	Air Sciences Inc. ENGINEERING CALCULATIONS	PROJECT TITLE: Solvay Package Boiler			BY: T. Martin
		PROJECT NO: 170-12-2	PAGE: 4	OF: 5	SHEET: Applicability
		SUBJECT: Emissions Inventory	DATE: July 2, 2012		

SUMMARY OF PROJECTED ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	New Package Boiler	New	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	130,049	130,264
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	5.3	5.3	5.3	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	9.2	9.2	9.2	0	0	0	0	0	152,304	152,304
16	Dryer Area	Debottlenecked	3.9	3.9	3.9	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	71.8	71.8	71.8	321.2	1554.9	4.4	1498.1	0.0269	470,255	472,272
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	21.5	21.5	21.5	12.0	1238.0	0	197.1	0.0003	184,152	184,218
50	"C" Train Dryer Area	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	4.4	4.4	4.4	41.3	206.7	0	1.3	0.0002	177,020	177,066
52	Product Silo - Top #2	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	2.0	2.0	2.0	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.7	10.7	10.7	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	41.3	41.3	41.3	55.7	2921.3	0	176.0	0.0005	330,014	330,138
81	"D" Train Dryer Area	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	12.4	12.4	12.4	73.0	34.1	0	1.3	0.0002	215,298	215,352
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.9	0.9	0.9	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	233.0	233.0	233.0	515.5	6022.8	5.0	1879.7	0.0287	1,659,093	1,661,614

SUMMARY OF PROJECTED ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	1.3	0	N/A	0	N/A
35	Sulfite Dryer	Existing	6.13	6.13	6.13	0	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0.44	0.44	0.44	0	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0.35	0.35	0.35	0	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0.31	0.31	0.31	0	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	1.18	1.18	1.18	0	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0.22	0.22	0.22	0	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0.22	0.22	0.22	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	1.31	1.31	1.31	0	0	N/A	0	N/A
105	S-300 Dryer #1	New	5.6	5.6	5.6	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0.3	0.3	0.3	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	5.6	5.6	5.6	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0.3	0.3	0.3	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0.9	0.9	0.9	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	8.9	8.9	8.9	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	2.7	3.9	N/A	1.9	N/A
E4	GM 8.1L (GVBH Pump)	New	0	0	0	1.4	2.0	N/A	1	N/A
E5	GM 4.3L (GVBH Pump)	New	0	0	0	0.8	1.2	N/A	0.6	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	25.7	15.0	N/A	3.6	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0.2	0.2	0.2	2.6	3.2	N/A	0.4	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer. Gen.)	New	0.1	0.1	0.1	1.0	0.9	N/A	0.1	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0.6	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0.1	0.1	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	1.2	1.2	N/A	0.8	N/A
		Total >	33.1	33.1	33.1	38.8	29.3	N/A	9.2	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary.

Appendix D: Estimation of Annual GHG Emissions from Gas-Fueled Boiler

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 1	OF: 3	SHEET: GHG Sources
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: June 12, 2012		

ACTUAL ANNUAL OPERATING HOURS AND THROUGHPUTS - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ		Annual Operating Hours (hr/yr)					Throughput (ton/yr) *				
Source ID	Source Description	2006	2007	2008	2009	2010	2006	2007	2008	2009	2010
15	DR-1 & 2 Steam Tube Dryers	8,364	8,408	8,159	8,131	8,392	967,105	944,140	755,359	786,186	771,037
17	"A" and "B" Calciners	8,507	8,627	8,344	8,673	8,276	1,202,621	1,592,932	1,566,774	1,773,989	1,439,276
48	"C" Calciner	7,580	4,813	3,739	4,420	3,853	1,046,548	540,553	422,508	443,485	476,594
51	Product Dryer #5	8,027	8,361	8,473	8,029	8,432	722,311	819,929	805,135	729,938	812,220
80	"D" Ore Calciner	7,671	7,655	8,133	6,254	8,099	1,516,472	1,677,003	1,792,095	1,300,723	1,814,177
82	DR-6 Product Dryer	8,689	8,466	8,400	8,098	8,539	789,384	819,496	1,008,988	884,317	964,228

* Conservatively assume that throughput is 100% trona ore for the calciners (#17, #48, #80) and 100% soda ash product for the dryers (#15, #51, #82).

ACTUAL ANNUAL OPERATING FUEL CONSUMPTION - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ			Coal Consumption (tons/year)					Coal Usage (MMBtu/yr) *				
Source ID	Source Description	Fuel	2006	2007	2008	2009	2010	2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Coal	47,086	102,883	101,966	112,190	101,167	941,720	2,057,660	2,039,320	2,243,800	2,023,340

* Assuming coal thermal equivalent of 10,000 Btu/lb.

WDEQ			Gas Consumption (MMscf/year)					Gas Usage (MMBtu/year) *				
Source ID	Source Description	Fuel	2006	2007	2008	2009	2010	2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Gas	507	---	---	---	---	517,140	---	---	---	---
48	"C" Calciner	Gas	1,004	555	432	484	463	1,024,080	566,100	440,640	493,680	472,260
51	Product Dryer #5	Gas	609	678	704	649	697	621,180	691,560	718,080	661,980	710,940
80	"D" Ore Calciner	Gas	1,465	1,709	1,899	1,347	1,788	1,494,300	1,743,180	1,936,980	1,373,940	1,823,760
82	DR-6 Product Dryer	Gas	678	672	829	727	778	691,560	685,440	845,580	741,540	793,560

* Assuming natural gas thermal equivalent of 1,020 Btu/scf.

NEW BOILER PARAMETERS

WDEQ Source ID	Source Description	Fuel(s)	Annual Hours	Thermal Rating (MMBtu/hr)	Max. Gas Usage (MMBtu/yr) *	Valves	Connectors (flanges)
---	New Package Boiler	Gas	8760	254	2,225,040	6	18

* Assuming natural gas thermal equivalent of 1,020 Btu/scf.

EMISSION FACTORS

Pollutant	Combustion ** EF (kg/MMBtu) Gas	Combustion ** EF (kg/MMBtu) Coal *	Combustion ** EF (lb/MMBtu) Gas	Combustion ** EF (lb/MMBtu) Coal *	Process *** EF Trona Ore (ton CO_2/ton)	Process *** EF Soda Ash Produced (ton CO_2/ton)	Fugitives **** Valve (scf/hr/component)	Fugitives **** Connector (scf/hr/component)	GWP Multiplier
CO_2	53.02	97.02	116.9	213.9	0.097	0.138	---	---	1
CH_4	0.001	0.011	0.002	0.02	---	---	2.903	0.396	21
N_2O	0.0001	0.0016	0.0002	0.004	---	---	---	---	310

* For subbituminous coal.

** From 40 CFR 98, Subpart C, Tables C-1 and C-2.

*** Per 40 CFR 98.293 (40 CFR 98, Subpart CC - Soda Ash Manufacturing), Eq. CC-1 for trona ore (applicable to calciners) and Eq. CC-2 for soda ash produced (applicable to dryers).

**** Per 40 CFR 98, Subpart W, Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production) Western U.S., Population Emission Factors - All Components, Gas Service; assume all gas emitted as methane to be conservative.

Assumptions			Reference
Coal thermal equivalent	10,000	Btu/lb	Solvay
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Density of Natural Gas	0.042	lb/scf	AP-42, Section 1.4 (Revision 7/98)

Conversions	
453.59	g/lb
2000	lb/ton
2.20462	lb/kg

Blue are input values and black are calculated values.

PROJECTED GHG MASS EMISSION INCREASES FROM NEW BOILER AND DEBOTTLENECKED SOURCES

Assumptions:

1) There are no short-term increases in PTE for all sources.
2) No existing debottlenecked sources will be physically modified.

3) The average production over the past five years is: 2,549,717 tons/year (based on avg. throughput for AQD #7 from 2006 to 2010)
4) Debottleneck results in production increase of: 360,000 tons/year
5) Assume projected annual emissions of existing debottlenecked sources are a function of the production increase (%): 14.1%

GHG Mass Emissions

WDEQ Source ID	Source Description	Actual Annual GHG Mass Emissions (tons/yr) 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
Process Emissions									
---	New Package Boiler	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	133,460	130,291	104,240	108,494	106,403	117,265	152,304	35,039
17*	"A" and "B" Calciners	116,654	154,514	151,977	172,077	139,610	153,246	196,373	43,127
48*	"C" Calciner	101,515	52,434	40,983	43,018	46,230	46,708	115,848	69,140
51*	Product Dryer #5	99,679	113,150	111,109	100,731	112,086	112,129	129,126	16,997
80*	"D" Ore Calciner	147,098	162,669	173,833	126,170	175,975	168,251	200,821	32,570
82*	DR-6 Product Dryer	108,935	113,090	139,240	122,036	133,063	126,165	158,900	32,735
Combustion Emissions									
---	New Package Boiler	0	0	0	0	0	0	130,044	130,044
15**	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0
17*	"A" and "B" Calciners	130,951	220,087	218,126	239,997	216,416	219,107	273,883	54,776
48*	"C" Calciner	59,853	33,086	25,754	28,853	27,602	29,420	68,304	38,884
51*	Product Dryer #5	36,305	40,419	41,969	38,690	41,551	41,194	47,894	6,701
80*	"D" Ore Calciner	87,335	101,881	113,208	80,301	106,591	107,545	129,192	21,647
82*	DR-6 Product Dryer	40,419	40,061	49,421	43,340	46,380	44,741	56,398	11,658
Fugitive Emissions *									
---	New Package Boiler	---	---	---	---	---	0	5	5
	Subtotals >	---	---	---	---	---	1,165,771	1,659,093	493,321

* For the existing sources (#15, #17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions.
** Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used so there are no actual gaseous combustion emissions.
*** Fugitive emissions of natural gas for new valves and connectors (flanges) associated with the new boiler.

GHG Mass Emissions by Constituent

WDEQ Source ID	Source Description	CO_2 (tons/yr) BAE	PAE	Increase	CH_4 (tons/yr) BAE	PAE	Increase	N_2O (tons/yr) BAE	PAE	Increase
Process Emissions										
---	New Package Boiler	0	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	117,265	152,304	35,039	0	0	0	0	0	0
17	"A" and "B" Calciners	153,246	196,373	43,127	0	0	0	0	0	0
48	"C" Calciner	46,708	115,848	69,140	0	0	0	0	0	0
51	Product Dryer #5	112,129	129,126	16,997	0	0	0	0	0	0
80	"D" Ore Calciner	168,251	200,821	32,570	0	0	0	0	0	0
82	DR-6 Product Dryer	126,165	158,900	32,735	0	0	0	0	0	0
Combustion Emissions										
---	New Package Boiler	0	130,041	130,041	0	2	2	0	0.2	0
15	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0	0
17	"A" and "B" Calciners	219,078	273,847	54,769	25	31	6	4	5	1
48	"C" Calciner	29,419	68,302	38,883	1	1	1	0.1	0.1	0
51	Product Dryer #5	41,193	47,893	6,700	1	1	0.1	0.1	0.1	0
80	"D" Ore Calciner	107,543	129,190	21,647	2	2	0.4	0.2	0.2	0
82	DR-6 Product Dryer	44,740	56,397	11,657	1	1	0.2	0.1	0.1	0
Fugitive Emissions										
---	New Package Boiler	0	0	0	0	5	5	0	0	0

PROJECTED GHG EMISSIONS INCREASES (CO_2e) FROM NEW BOILER AND DEBOTTLENECKED SOURCES

CO_2e Emissions

WDEQ Source ID	Source Description	Actual Annual CO_2e Emissions (tons/yr) 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
Process Emissions									
---	New Package Boiler	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	133,460	130,291	104,240	108,494	106,403	117,265	152,304	35,039
17*	"A" and "B" Calciners	116,654	154,514	151,977	172,077	139,610	153,246	196,373	43,127
48*	"C" Calciner	101,515	52,434	40,983	43,018	46,230	46,708	115,848	69,140
51*	Product Dryer #5	99,679	113,150	111,109	100,731	112,086	112,129	129,126	16,997
80*	"D" Ore Calciner	147,098	162,669	173,833	126,170	175,975	168,251	200,821	32,570
82*	DR-6 Product Dryer	108,935	113,090	139,240	122,036	133,063	126,165	158,900	32,735
Combustion Emissions									
---	New Package Boiler	0	0	0	0	0	0	130,169	130,169
15**	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0
17*	"A" and "B" Calciners	131,722	221,708	219,732	241,764	218,010	220,720	275,899	55,179
48*	"C" Calciner	59,911	33,118	25,778	28,881	27,628	29,448	68,369	38,921
51*	Product Dryer #5	36,340	40,458	42,009	38,727	41,591	41,233	47,940	6,707
80*	"D" Ore Calciner	87,419	101,979	113,317	80,378	106,693	107,648	129,316	21,668
82*	DR-6 Product Dryer	40,458	40,099	49,468	43,381	46,425	44,784	56,452	11,669
Fugitive Emissions									
---	New Package Boiler	0	0	0	0	0	0	95	95
	Subtotals >	---	---	---	---	---	1,167,598	1,661,614	494,015

* For the existing sources (#15, #17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions.

** Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used so there are no actual gaseous combustion emissions.

CO_2 equivalence (CO_2e) is calculated as follows:

CO_2e (ton/year) = (CO_2 ton/year x 1)+(CH_4 ton/year x 21)+(N_2O ton/year x 310)

Package Boiler Information

Boiler Size	254	MMBtu/hour
Hours of operation	8760	hr/year
Natural gas thermal equivalent	1020	Btu/scf

EMISSION FACTORS

General Natural Gas Factors (Weighted U.S. Average) [1]

	CO_2		CH_4		N_2O	
Pollutant	**(kg/MMBtu)**	**(lb/MMBtu)**	**(kg/MMBtu)**	**(lb/MMBtu)**	**(kg/MMBtu)**	**(lb/MMBtu)**
Natural Gas	53.02	116.9	0.001	0.0022	0.0001	0.00022

[1] From 40 CFR 98, Subpart C, Tables C-1 and C-2 (Natural Gas).

Solvay Gas Constituent Data and Associated CO_2 Emission Factors

Constituent	Composition % Volume	Molecular Weight	Composition % Mass	CO_2 EF [1] (kg/MMBtu)	CO_2 EF [1] (lb/MMBtu)
Carbon Dioxide	2.47%	44.01	6.0%	---	---
Nitrogen	0.61%	14.01	0.5%	0	0
Methane	90.45%	16.043	79.8%	52.26	115.2
Ethane	4.07%	30.07	6.7%	62.64	138.1
Propane	1.39%	44.09	3.4%	61.46	135.5
Iso Butane	0.24%	58.1	0.8%	64.91	143.1
Normal Butane	0.27%	58.1	0.9%	65.15	143.6
Iso Pentane [2]	0.13%	72.15	0.5%	70.02	154.4
Normal Pentane [2]	0.10%	72.15	0.4%	70.02	154.4
Hexane	0.24%	86.17	1.1%	67.72	149.3
Helium	0.03%	4.02	0.01%	0	0
	Average >	18.19			

[1] From 40 CFR 98, Subpart C, Table C-1, methane and hexane not available from 40 CFR 98 - values calculated.
Derivation of calculated values for methane and hexane are based on mass CO_2 emitted/mass fuel combusted and HHV for each fuel constituent.
Using methane as an example:
The combustion reaction for methane is: $CH_4 + 2O_2 \text{--->} CO_2 + 2H_2O$; so one mole of methane combusted results in one mole of CO_2 formed.
Molecular weight of CH_4 = 16.043 g/mol, CO_2 = 44.01 g/mol, so 2.74325 is the ratio of mass CO_2 per unit mass of fuel combusted.
HHV of the combustion of CH_4 is 23,811 Btu/lb.
The ratio of mass CO_2 per unit mass of fuel combusted divided by the HHV and converted to the appropriate units results in the CO_2 EF.
Example, (2.74325 lb CO_2/lb CH_4) x (1/23,811 Btu/lb) x (1 kg/2.20462 lb) x (1,000,000 Btu/MMBtu) = 52.2 kg CO_2/MMBtu = 115.2 lb CO_2/MMBtu.
Thus, the EFs for each constituent is based on mass and HHV.
[2] As Pentanes Plus

Weighted CO_2 Emission Factor Calculations

Constituent	Solvay Gas Composition % Mass	Weighted CO_2 EF * (lb/MMBtu)
Weighted CO_2 EF (no slip) [1]	94.0%	118.3
Weighted CO_2 EF (w/ slip) [2]	100.0%	125.3

[1] The weighted CO_2 EF based on the Composition Mass % multiply by the CO_2 EF (mass based with HHV incorporated) for each constituent divided by the total mass % without CO_2 slip included.
[2] Weighted CO_2 EF with 6% CO_2 slip applied.

GWP Multipliers

Fuel Type	**GWP Multiplier**
CO_2	1
CH_4	21
N_2O	310

PROPOSED GHG BACT LIMITS

Limit Based on Solvay Max. Heat Value Fuel

125.3	lb CO_2/MMBtu
0.0022	lb CH_4/MMBtu
0.00022	lb N_2O/MMBtu
125.3	lb CO_2e/MMBtu

Assumptions

1 mole methane (CH_4) combusts to form 1 mole CO_2		
1 mole hexane (C_6H_{14}) combusts to form 6 moles CO_2		
Molecular weight, CO_2	44.01	g/mol
Molecular weight, CH_4	16.043	g/mol
Molecular weight, C_6H_{14}	86.17	g/mol
HHV, CH_4	23,811	Btu/lb *
HHV, C_6H_{14}	20,526	Btu/lb *

* From: http://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html

Conversions

453.59	g/lb
2000	lb/ton
3600	sec/hr
1,000,000	Btu/MMBtu
2.20462	lb/kg

Appendix E: Incremental Costs for Added Boiler Insulation

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 1	OF: 4	SHEET:
ENGINEERING CALCULATIONS	SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 3" INSULATION VS. 4" INSULATION

Assumptions		Units	Reference
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530	ft^2	Solvay
Boiler Heat Loss	301,800	$BTU/ft^2/yr$	Solvay - 3" thick insulation
	231,400	$BTU/ft^2/yr$	Solvay - 4" thick insulation
Cost of Natural Gas	2.34	$/thousand ft^3	Solvay - current hub price
	0.00234	$/ ft^3	
	435,897	Btu/$	
	0.4359	MMBtu/$	
Cost of Insulation	$19.00	$/ ft^2	Solvay - cost of 3" thick insulation*
	$20.20	$/ ft^2	Solvay - cost of 4" thick insulation*
Cost of Insulating Boiler	$48,070		Solvay - cost of 3" thick insulation*
	$51,106		Solvay - cost of 4" thick insulation*
	$3,036	one time cost	Difference (4" vs. 3")
	$151.80	$/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.
** boiler expected life: e-mail from Davidson, Foster Wheeler, August 3, 2012

CALCULATIONS

Parameter		Units
Heat Loss		
3" Insulation	763.6	MMBtu/yr
4" Insulation	585.4	MMBtu/yr
Reduction in Heat Loss (4" vs. 3")	178.1	MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)		
3" Insulation	$1,752	$/yr
4" Insulation	$1,343	$/yr
Incremental Cost Savings (4" vs. 3")	$409	$/yr
Combined annualized insulation cost and fuel savings	-$257	$/yr
GHG Emissions Reduction (4" vs. 3")	10.41	GHG Mass (tpy)
	10.42	CO_2e (tpy)
Incremental Cost to Insulate to 4"	$15	$/ton GHG Mass
(fuel savings not considered)	$15	$/ton GHG CO2e
Incremental Cost to Insulate to 4"	-$25	$/ton GHG Mass
(with fuel savings considered)	-$25	$/ton GHG CO2e
Years to Pay Back *	7.4	years

* Calculated as the ratio of the cost of insulating the boiler (difference 4" vs. 3" insulation) and the incremental cost savings in fuel savings when using 4" vs. 3" insulation.

GHG EMISSION FACTORS

Pollutant	Gas Emission Factor * (kg/MMBtu)	(lb/MMBtu)	GWP Multiplier **
CO_2	53.02	116.9	1
CH_4	0.001	0.002	21
N_2O	0.0001	0.0002	310

* From 40 CFR 98, Subpart C, Tables C-1 and C-2.
** From 40 CFR 98, Subpart A, Appendix, Table A-1.

Conversions	
2000	lb/ton
2.20462	lb/kg

Blue are input values and black are calculated values.

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 4" INSULATION VS. 5" INSULATION

Assumptions	Units		Reference
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530	ft^2	Solvay
Boiler Heat Loss	231,400	$BTU/ft^2/yr$	Solvay - 4" thick insulation
	187,700	$BTU/ft^2/yr$	Solvay - 5" thick insulation
Cost of Natural Gas	2.34	$/thousand ft^3	Solvay - current hub price
	0.00234	$/ ft^3	
	435,897	Btu/$	
	0.4359	MMBtu/$	
Cost of Insulation	$20.20	$/ ft^2	Solvay - cost of 4" thick insulation*
	$24.15	$/ ft^2	Solvay - cost of 5" thick insulation*
Cost of Insulating Boiler	$51,106		Solvay - cost of 4" thick insulation*
	$61,100		Solvay - cost of 5" thick insulation*
	$9,994	one time cost	Difference (5" vs. 4")
	$400	$/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter		Units
Heat Loss		
4" Insulation	585.4	MMBtu/yr
5" Insulation	474.9	MMBtu/yr
Reduction in Heat Loss (5" vs. 4")	110.6	MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)		
4" Insulation	$1,343	$/yr
5" Insulation	$1,089	$/yr
Incremental Cost Savings (5" vs. 4")	$254	$/yr
Combined annualized insulation cost and fuel savings	$146	$/yr
GHG Emissions Reduction (5" vs. 4")	6.46	GHG Mass (tpy)
	6.47	CO_2e (tpy)
Incremental Cost to Insulate to 5"	$62	$/ton GHG Mass
(fuel savings not considered)	$62	$/ton GHG CO2e
Incremental Cost to Insulate to 5"	$23	$/ton GHG Mass
(with fuel savings considered)	$23	$/ton GHG CO2e
Years to Pay Back *	39.4	years

* Calculated as the ratio of the cost of insulating the boiler (difference 5" vs. 4" insulation) and the incremental cost savings in fuel savings when using 5" vs. 4" insulation.

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 5" INSULATION VS. 6" INSULATION

Assumptions		Units	Reference
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530	ft^2	Solvay
Boiler Heat Loss	187,700	BTU/ft^2/yr	Solvay - 5" thick insulation
	158,000	BTU/ft^2/yr	Solvay - 6" thick insulation
Cost of Natural Gas	2.34	$/thousand ft^3	Solvay - current hub price
	0.00234	$/ ft^3	
	435,897	Btu/$	
	0.4359	MMBtu/$	
Cost of Insulation	$24.15	$/ ft^2	Solvay - cost of 5" thick insulation*
	$25.35	$/ ft^2	Solvay - cost of 6" thick insulation*
Cost of Insulating Boiler	$61,100		Solvay - cost of 5" thick insulation*
	$64,136		Solvay - cost of 6" thick insulation*
	$3,036	one time cost	Difference (5" vs. 6")
	$121	$/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter		Units
Heat Loss		
5" Insulation	474.9	MMBtu/yr
6" Insulation	399.7	MMBtu/yr
Reduction in Heat Loss (5" vs. 6")	75.1	MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)		
5" Insulation	$1,089	$/yr
6" Insulation	$917	$/yr
Incremental Cost Savings (5" vs. 6")	$172	$/yr
Combined annualized insulation cost and fuel savings	-$51	$/yr
GHG Emissions Reduction (5" vs. 6")	4.39	GHG Mass (tpy)
	4.40	CO_2e (tpy)
Incremental Cost to Insulate to 6"	$28	$/ton GHG Mass
(fuel savings not considered)	$28	$/ton GHG CO2e
Incremental Cost to Insulate to 6"	-$12	$/ton GHG Mass
(with fuel savings considered)	-$12	$/ton GHG CO2e
Years to Pay Back *	17.6	years

* Calculated as the ratio of the cost of insulating the boiler (difference 5" vs. 6" insulation) and the incremental cost savings in fuel savings when using 5" vs. 6" insulation.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 4	OF: 4	SHEET:
ENGINEERING CALCULATIONS	SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 3" INSULATION VS. 6" INSULATION

Assumptions		Units	Reference
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530	ft^2	Solvay
Boiler Heat Loss	301,800	BTU/ft^2/yr	Solvay - 3" thick insulation
	158,000	BTU/ft^2/yr	Solvay - 6" thick insulation
Cost of Natural Gas	2.34	\$/thousand ft^3	Solvay - current hub price
	0.00234	\$/ ft^3	
	435,897	Btu/\$	
	0.4359	MMBtu/\$	
Cost of Insulation	\$19.00	\$/ ft^2	Solvay - cost of 3" thick insulation*
	\$25.35	\$/ ft^2	Solvay - cost of 6" thick insulation*
Cost of Insulating Boiler	\$48,070		Solvay - cost of 3" thick insulation*
	\$64,136		Solvay - cost of 6" thick insulation*
	\$16,066	one time cost	Difference (6" vs. 3")
	\$643	\$/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter		Units
Heat Loss		
3" Insulation	763.6	MMBtu/yr
6" Insulation	399.7	MMBtu/yr
Reduction in Heat Loss (6" vs. 3")	363.8	MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)		
3" Insulation	\$1,752	\$/yr
6" Insulation	\$917	\$/yr
Incremental Cost Savings (6" vs. 3")	\$835	\$/yr
Combined annualized insulation cost and fuel savings	-\$192	\$/yr
GHG Emissions Reduction (6" vs. 3")	21.26	GHG Mass (tpy)
	21.28	CO_2e (tpy)
Incremental Cost to Insulate to 6"	\$30	\$/ton GHG Mass
(fuel savings not considered)	\$30	\$/ton GHG CO2e
Incremental Cost to Insulate to 6"	-\$9	\$/ton GHG Mass
(with fuel savings considered)	-\$9	\$/ton GHG CO2e
Years to Pay Back *	19.2	years

* Calculated as the ratio of the cost of insulating the boiler (difference 6" vs. 3" insulation) and the incremental cost savings in fuel savings when using 6" vs. 3" insulation.

Appendix F: US Fish and Wildlife Service – List of Threatened and Endangered Species

United States Department of the Interior

FISH AND WILDLIFE SERVICE
WYOMING ECOLOGICAL SERVICES FIELD OFFICE
5353 Yellowstone Rd, Suite 308A
CHEYENNE, WY 82009
PHONE: (307)772-2374 FAX: (307)772-2358
URL: www.fws.gov/wyominges/

Consultation Tracking Number: 06E13000-2012-SLI-0295 July 05, 2012
Project Name: Solvay Chemicals, Inc.

Subject: List of threatened and endangered species that may occur in your proposed project location, and/or may be affected by your proposed project.

To Whom It May Concern:

The enclosed species list identifies threatened, endangered, and proposed species, designated critical habitat, and candidate species that may occur within the boundary of your proposed project and/or may be affected by your proposed project. The species list fulfills the requirements of the U.S. Fish and Wildlife Service (Service) under section 7(c) of the Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 et seq.).

New information based on updated surveys, changes in the abundance and distribution of species, changed habitat conditions, or other factors could change this list. Please note that under 50 CFR 402.12(e) of the regulations implementing section 7 of the Act, the accuracy of this species list should be verified after 90 days. This verification can be completed formally or informally as desired. The Service recommends that verification be completed by visiting the Environmental Conservation Online System-Information, Planning, and Conservation System (ECOS-IPaC) website at regular intervals during project planning and implementation for updates to species lists and information. An updated list may be requested through the ECOS-IPaC system by completing the same process used to receive the enclosed list.

Please feel free to contact us if you need more information or assistance regarding the potential impacts to federally proposed, listed, and candidate species and federally designated and proposed critical habitat. We also encourage you to visit the Wyoming Ecological Services website at http://www.fws.gov/wyominges/Pages/Species/Species_Endangered.html for more information about species occurrence and designated critical habitat.

The purpose of the Act is to provide a means whereby threatened and endangered species and the ecosystems upon which they depend may be conserved. Under sections 7(a)(1) and 7(a)(2) of the Act and its implementing regulations (50 CFR 402 et seq.), Federal agencies are required to use their authorities to carry out programs for the conservation of threatened and endangered species and to determine whether projects may affect threatened and endangered species and/or designated critical habitat.

A biological assessment is required for construction projects (or other undertakings having similar physical impacts) that are major Federal actions significantly affecting the quality of the human environment as defined in the National Environmental Policy Act (42 U.S.C. 4332(2)(c)). For projects other than major construction activities, the Service suggests that a biological evaluation similar to a biological assessment be prepared to determine whether the project may affect listed or proposed species and/or designated or proposed critical habitat. Recommended contents of a biological assessment are described at 50 CFR 402.12.

If a Federal agency determines, based on the biological assessment or biological evaluation, that listed species and/or designated critical habitat may be affected by the proposed project, the agency is required to consult with the Service pursuant to 50 CFR 402. In addition, the Service recommends that candidate species, proposed species, and proposed critical habitat be addressed within the consultation. More information on the regulations and procedures for section 7 consultation, including the role of permit or license applicants, can be found in the "Endangered Species Consultation Handbook" at: http://www.fws.gov/endangered/esa-library/pdf/TOC-GLOS.PDF

We also recommend that you consider the following information when assessing impacts to federally listed species, as well as migratory birds, and other trust resources:

Colorado River and Platte River Systems: Consultation under section 7 of the Act is required for projects in Wyoming that may lead to water depletions or have the potential to impact water quality in the Colorado River system or the Platte River system, because these actions may affect threatened and endangered species inhabiting the downstream reaches of these river systems. In general, depletions include evaporative losses and/or consumptive use of surface or groundwater within the affected basin, often characterized as diversions minus return flows. Project elements that could be associated with depletions include, but are not limited to: ponds, lakes, and reservoirs (e.g., for detention, recreation, irrigation, storage, stock watering, municipal storage, and power generation); hydrostatic testing of pipelines; wells; dust abatement; diversion structures; and water treatment facilities.

Species that may be affected in the Colorado River system include the endangered bonytail (*Gila elegans*), Colorado pikeminnow (*Ptychocheilus lucius*), humpback chub (*Gila cypha*), and razorback sucker (*Xyrauchen texanus*) and their designated critical habitats. Projects in the Platte River system may impact the endangered interior population of the least tern (*Sterna antillarum*), the endangered pallid sturgeon (*Scaphirhynchus albus*), the threatened piping plover (*Charadrius melodus*), the threatened western prairie fringed orchid (*Platanthera praeclara*), as well as the endangered whooping crane (*Grus americana*) and its designated critical habitat. For more information on consultation requirements for the Platte River species, please visit http://www.fws.gov/platteriver.

Migratory Birds: The Migratory Bird Treaty Act (16 U.S.C. 703-712), prohibits the taking of any migratory birds, their parts, nests, or eggs except as permitted by regulations, and does not require intent to be proven. Except for introduced species and some upland game birds, almost all birds occurring in the wild in the United States are protected (50 CFR 10.13). Guidance for minimizing impacts to migratory birds for projects that include communications towers (e.g., cellular, digital television, radio, and emergency broadcast) can be found at http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/towers.htm.

The Bald and Golden Eagle Protection Act (16 U.S.C. 668-668d) prohibits knowingly taking, or taking with wanton disregard for the consequences of an activity, any bald or golden eagles or their body parts, nests, or eggs, which includes collection, molestation, disturbance, or killing. Eagle nests are protected whether they are active or inactive. Removal or destruction of nests, or causing abandonment of a nest could constitute a violation of one or both of the above statutes. Projects affecting eagles may require development of an eagle conservation plan (http://www.fws.gov/windenergy/eagle_guidance.html). Additionally, wind energy projects should follow the wind energy guidelines (http://www.fws.gov/windenergy/) for minimizing impacts to migratory birds and bats.

If nesting migratory birds are present on or near the project area, timing of activities is an important consideration and should be addressed in project planning. Activities that could lead to the take of migratory birds or eagles, their young, eggs, or nests, should be coordinated with our office prior to project implementation. If nest manipulation (including removal) is proposed for the project, the project proponent should contact the Migratory Bird Office in Denver at 303-236-8171 to see if a permit can be issued for the project. If a permit cannot be issued, the project may need to be modified to protect migratory birds, eagles, their young, eggs, and nests.

We appreciate your concern for threatened and endangered species. The Service encourages Federal agencies to include conservation of threatened and endangered species into their project planning to further the purposes of the Act. Please include the Consultation Tracking Number in the header of this letter with any request for consultation or correspondence about your project that you submit to our office.

Attachment

United States Department of Interior
Fish and Wildlife Service

Project name: Solvay Chemicals, Inc.

Official Species List

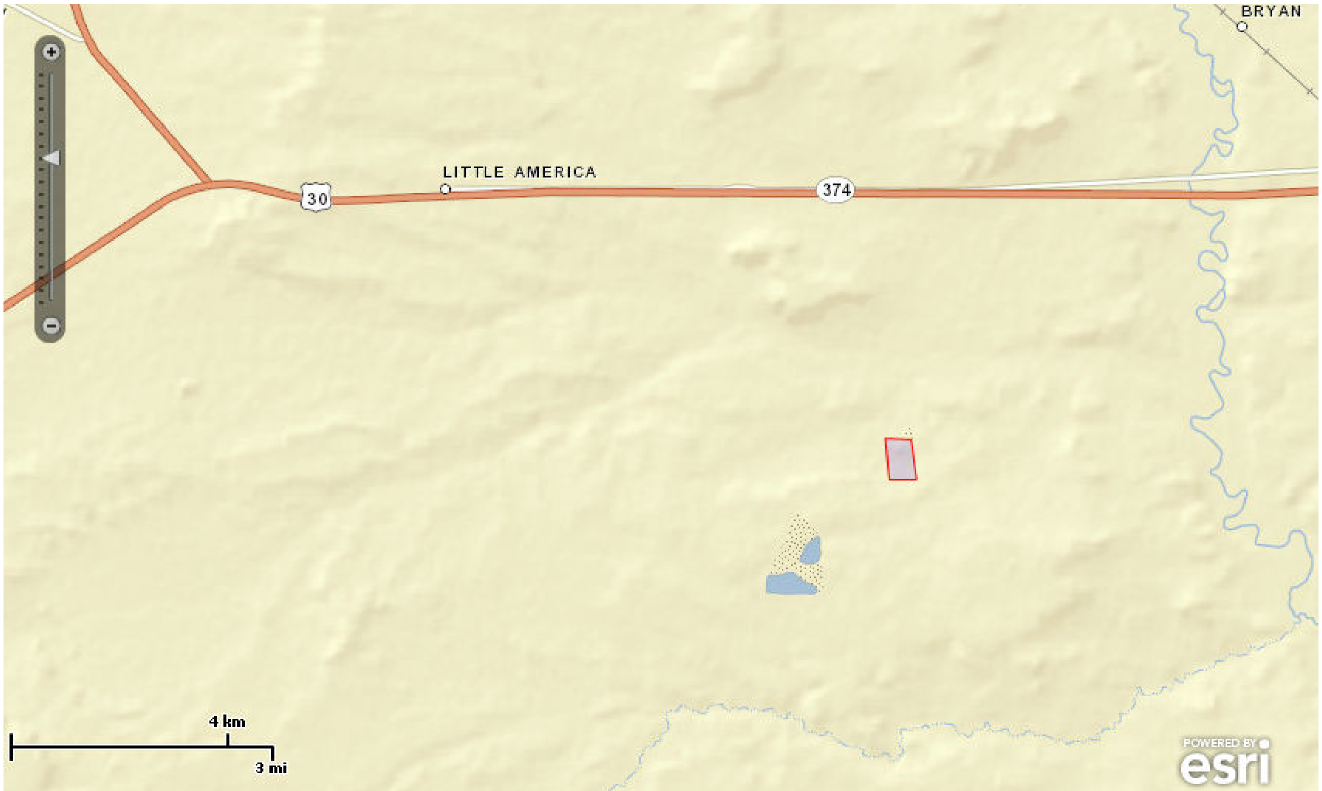
Provided by:

WYOMING ECOLOGICAL SERVICES FIELD OFFICE
5353 Yellowstone Rd, Suite 308A

CHEYENNE, WY 82009
(307) 772-2374
http://www.fws.gov/wyominges/

Consultation Tracking Number: 06E13000-2012-SLI-0295
Project Type: Mining
Project Description: Addition of 253MMBtu/hr gas fired boiler to existing processing facility.

Project Location Map:



Project Coordinates: MULTIPOLYGON (((-109.7610494 41.502183, -109.7552902 41.5020094, -109.7541229 41.4953367, -109.7602426 41.4952403, -109.7610494 41.502183)))

Project Counties: Sweetwater, WY

Endangered Species Act Species List

Species lists are not entirely based upon the current range of a species but may also take into consideration actions that affect a species that exists in another geographic area. For example, certain fish may appear on the species list because a project could affect downstream species. Please contact the designated FWS office if you have questions.

Black-Footed ferret *(Mustela nigripes)*

Population: entire population, except where EXPN

Listing Status: Endangered

Blowout penstemon *(Penstemon haydenii)*

Listing Status: Endangered

Bonytail chub *(Gila elegans)*

Population: entire

Listing Status: Endangered

Colorado pikeminnow *(Ptychocheilus lucius)*

Population: except Salt and Verde R. drainages, AZ

Listing Status: Endangered

Greater sage-grouse *(Centrocercus urophasianus)*

Population: entire

Listing Status: Candidate

Humpback chub *(Gila cypha)*

Population: entire

Listing Status: Endangered

Razorback sucker *(Xyrauchen texanus)*

Population: entire

Listing Status: Endangered

Ute ladies'-tresses *(Spiranthes diluvialis)*

Listing Status: Threatened

Yellow-Billed Cuckoo *(Coccyzus americanus)*

Population: Western U.S. DPS

Listing Status: Candidate

Appendix I: Characterization of Mobile Sources and Cooling Towers for Modeling

COOLING TOWER EMISSION ESTIMATES FOR MODELING

Cooling Tower Flow Rates (V)

High Flow (901)	15,000	gal/min
Low Flow (902)	5,500	gal/min

Electrical Conductivity (EC)

High Flow (901)	4,550	uS/cm	98th Percentile Daily Average (2009-2011 Solvay EC Data)
Low Flow (902)	8,683	uS/cm	98th Percentile Daily Average (2009-2011 Solvay EC Data)

Total Dissolved Solids (TDS): TDS(ppm) = 0.67 * EC (uS/cm)

Source: http://www.stevenswater.com/water_quality_sensors/conductivity_info.html

High Flow (901)	3,048	ppm
Low Flow (902)	5,818	ppm

Particulate Emission Rate Estimates, E *

E = V(gal/min) x TDS(ppm)/10^6 x Ndrift(%)/100 x Dh2o x 60 min/hr

	High Flow (901)	Low Flow (902)	**Reference**
Cooling Tower flow Rate (V)=	15,000 gal/min	5,500 gal/min	
Total Dissolved Solids (TDS) =	3,048 ppm	5,818 ppm	
Drift Loss (Ndrift) =	0.005 %	0.005 %	Typical value for towers with drift eliminators. *
Density of Water (Dh2o) =	8.34 lb/gal	8.34 lb/gal	

* Source: http://www.louisvilleky.gov/NR/rdonlyres/FDCC1304-707F-4A21-A54E-C4CE60990734/0/FormE44WetCoolingTower.pdf

	High Flow (901)	Low Flow (902)
PM Emissions =	1.14 lb/hr	0.80 lb/hr
	5.0 tons/year	3.5 tons/year
PM_{10} Emissions * =	0.46 lb/hr	0.29 lb/hr
	2.0 tons/year	1.3 tons/year
$PM_{2.5}$ Emissions * =	0.070 lb/hr	0.011 lb/hr
	0.31 tons/year	0.05 tons/year

* See size fraction calculations on pages 2 and 3.

Blue values are input values and black are calculated values.

COOLING TOWER EMISSION ESTIMATES FOR MODELING, CONTD.

High Flow (901): PM_{10}/PM and $PM_{2.5}$/PM Mass Fraction Calculations

		Reference
TDS	3,048 ppm	Solvay
Calcium Carbonate Density	2.7 g/cc	Perry's Chemical Engineer's Handbook, Sixth Edition, p. 3-10.
Volume of Sphere	$V = 4/3*PI*r^3$	

High Flow (901)

Water Drop Size Distribution*

Droplet Dia. (micron)	% mass	Water Droplet Vol. (cc)	Water Droplet Mass (g)	Solids Mass (g)	Solids Vol. (cc)	Solids Dia. (micron)		
22	0.43	5.6E-09	5.6E-09	1.7E-11	6.3E-12	2.3		
29	1.49	1.3E-08	1.3E-08	3.9E-11	1.4E-11	3.0	1.9	< (% mass < ~2.5 microns)
44	3.76	4.5E-08	4.5E-08	1.4E-10	5.0E-11	4.6		
58	2.09	1.0E-07	1.0E-07	3.1E-10	1.2E-10	6.0		
65	1.86	1.4E-07	1.4E-07	4.4E-10	1.6E-10	6.8		
87	1.56	3.4E-07	3.4E-07	1.1E-09	3.9E-10	9.1		
108	1.43	6.6E-07	6.6E-07	2.0E-09	7.4E-10	11.2	12.6	< (% mass < ~10 microns)
120	1.26	9.0E-07	9.0E-07	2.8E-09	1.0E-09	12.5		
132	1.09	1.2E-06	1.2E-06	3.7E-09	1.4E-09	13.7		
144	1.32	1.6E-06	1.6E-06	4.8E-09	1.8E-09	15.0		
174	5.81	2.8E-06	2.8E-06	8.4E-09	3.1E-09	18.1		
300	5.04	1.4E-05	1.4E-05	4.3E-08	1.6E-08	31.2		
450**	4.17	4.8E-05	4.8E-05	1.5E-07	5.4E-08	46.9	31.3	< (% mass < 450 microns)
Total	31.3							

* Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1 Technical Report. EPA 600 7-79-251a, Nov. 1979, Pages 59 and 60.

** Maximum droplet size governed by atmospheric dispersion.

High Flow: PM_{10}/PM Mass Fraction = 0.40

High Flow: $PM_{2.5}$/PM Mass Fraction = 0.06

COOLING TOWER EMISSION ESTIMATES FOR MODELING, CONTD.

Low Flow (902): PM_{10}/PM and $PM_{2.5}$/PM Mass Fraction Calculations

		Reference
TDS	5,818 ppm	Solvay
Calcium Carbonate Density	2.7 g/cc	Perry's Chemical Engineer's Handbook, Sixth Edition, p. 3-10.
Volume of Sphere	$V = 4/3*PI*r^3$	

Low Flow (902)
Water Drop Size Distribution*

Droplet Dia. (micron)	% mass	Water Droplet Vol. (cc)	Water Droplet Mass (g)	Solids Mass (g)	Solids Vol. (cc)	Solids Dia. (micron)		
22	0.43	5.6E-09	5.6E-09	3.2E-11	1.2E-11	2.8	0.43	< % mass < ~2.5 microns
29	1.49	1.3E-08	1.3E-08	7.4E-11	2.8E-11	3.7		
44	3.76	4.5E-08	4.5E-08	2.6E-10	9.6E-11	5.7		
58	2.09	1.0E-07	1.0E-07	5.9E-10	2.2E-10	7.5		
65	1.86	1.4E-07	1.4E-07	8.4E-10	3.1E-10	8.4		
87	1.56	3.4E-07	3.4E-07	2.0E-09	7.4E-10	11.2	11.2	< % mass < ~10 microns
108	1.43	6.6E-07	6.6E-07	3.8E-09	1.4E-09	13.9		
120	1.26	9.0E-07	9.0E-07	5.3E-09	1.9E-09	15.5		
132	1.09	1.2E-06	1.2E-06	7.0E-09	2.6E-09	17.0		
144	1.32	1.6E-06	1.6E-06	9.1E-09	3.4E-09	18.6		
174	5.81	2.8E-06	2.8E-06	1.6E-08	5.9E-09	22.5		
300	5.04	1.4E-05	1.4E-05	8.2E-08	3.0E-08	38.7		
450**	4.17	4.8E-05	4.8E-05	2.8E-07	1.0E-07	58.1	31.3	< % mass < 450 microns
Total	31.3							

* Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1 Technical Report. EPA 600 7-79-251a, Nov. 1979, Pages 59 and 60.
** Maximum droplet size governed by atmospheric dispersion.

Low Flow: PM_{10}/PM Mass Fraction = 0.36
Low Flow: $PM_{2.5}$/PM Mass Fraction = 0.01

DECA ROAD EMISSION ESTIMATES FOR MODELING

Unpaved Roads PM_{10} Emission Factor — **Reference**

EF (lb PM_{10}/VMT) = k * (s/12)^a * (W/3)^b — AP-42, Section 13.2.2 (Revision 11/06), Page 13.2.2-4

k =	1.5		Constant	
s =	8.4	%	Silt content	Haul road, western surface coal mine (AP-42, Table 13.2.2-1)
a =	0.9		Constant	
W =	44.4	tons	Average Truck Weight	Solvay
b =	0.45		Constant	
EF =	3.66	lb PM_{10}/VMT	Uncontrolled Emission Factor	
CE * =	91	%	Control Efficiency (Mag Chloride)	
EF' =	0.329	lb PM_{10}/VMT	Controlled Emission Factor	

* Per Solvay's permit, the DECA road fugitive dust emissions are controlled with monthly applications of 30% magnesium chloride applied at a rate of 0.33 to 0.050 gallon per square yard in conjunction with water applications sufficient to control fugitive dust. The control efficiency here is based on AP-42, Chapter 13.2.2, Unpaved Roads. Figure 13.2.2-2 provides the control efficiencies achievable with watering (max of 95%) and Figure 13.2.2-5 provides the control efficiencies achievable with petroleum resins (max of 91%). Solvay uses a combination of watering and chemical dust suppressants, applied to achieve a maximum control efficiency. Therefore, as a conservative estimate, the lower of the two maximum control efficiencies is used.

Unpaved Roads PM_{10} Emission Rate, E_{PM10}

E_{PM10} = EF' * NT * RTD

Where,

EF' = Controlled emission factor

NT = Number of trips

RTD = Round trip distance (miles)

Annual Number Trips			**Reference**
W_{load} =	35	tons/load	Solvay
W_{total_annual} =	425,000	tons/year	Solvay - annual tons material hauled
NT (W_{total_an}/W_{load}) =	12,143	trips per year	Solvay - annual trips

Daily Number Trips

W_{total_daily} =	1,500	tons/day	Solvay - max. daily tons material hauled
NT (W_{total_daily}/W_{load}) =	43	trips/day	Solvay - maximum daily trips

Round Trip Distance

RTD =	3.73	miles/trip	Estimated round trip distance for modeling

Unpaved Road Particulate Emissions

Daily Emissions, PM_{10} ***

E_{PM10} =	52.8	lb/day
E_{PM10} =	2.20	lb/hr

Daily Emissions, $PM_{2.5}$ **, ***

$E_{PM2.5}$ =	5.3	lb/day
$E_{PM2.5}$ =	0.22	lb/hr

Annual Emissions, PM_{10}

E_{PM10} =	7.5	tons/year
	1.70	annualized lb/hr *

Annual Emissions, $PM_{2.5}$ **

$E_{PM2.5}$ =	0.7	tons/year
	0.17	annualized lb/hr *

* Assuming 8,760 hours of operation per year.

** The emission factor calculations above are a linear function of the constant k. Per AP-42, Section 13.2.2, Table 13.2.2-2, k for $PM_{2.5}$ equals 0.15 and k for PM_{10} equals 1.5. Therefore, a $PM_{2.5}$/PM_{10} mass fraction of 0.1 (i.e., 0.15/1.5) is applied to the PM_{10} emission rate to calculate a $PM_{2.5}$ emission rate for the haul road.

*** Per WDEQ policy, short-term fugitive particulate emissions are not modeled.

DECA ROAD EMISSION ESTIMATES FOR MODELING, CONTD.

DECA Haul Road Exhaust Emissions

			Reference
Truck Model:	Komatsu HM350-2		Solvay, USEPA Tier III compliant
Model Year:	2007		Solvay
Number Trucks:	2		Solvay
Max. Gross Engine Rating:	408	hp	Solvay/Manufacturer
Fuel Usage per Truck:	40	gal/day/truck	Solvay
Fuel Usage for 2 Trucks:	80	gal/day	Two trucks operating at 40 gal/day/truck (i.e., 80 gal/day) divided
Fuel Usage per Trip:	1.86	gal/trip	by max. number trips per day (43).
Number of Round Trips/hr (RT):	4	trips/hour	Solvay
Fuel Usage per Hour (F):	7.44	gal/hr	Fuel usage per hour based on 4 trips per hour for both trucks.
Heat Content of Diesel Fuel (HC):	137,000	Btu/gal	AP-42, Appendix A, Rev. 9/85, P. A-5.
Average BSFC:	7,000	Btu/hp-hr	AP-42, 3.3-1 footnote, Rev. 10/96, P. 3.3-6.
Avg. power based on Solvay fuel use (fHP):	145.6	hp	fHP = F *HC/BSFC*RT

USEPA Tier III Emission Factors, Non-Road Engines (300< hp< 600)

CO	2.6	g/bhp-hr
NOx+NMHC	3	g/bhp-hr
PM	0.15	g/bhp-hr

Short-Term Emission Rate: Exhaust Only

E = EF * fHP

CO	0.83	lb/hr
NOx	0.96	lb/hr
PM_{10}	0.05	lb/hr
$PM_{2.5}$	0.05	lb/hr

Short-Term Emission Rate: Exhaust and Unpaved Road Fugitives

E = EF * fHP + Unpaved Road Fugitive Emissions

CO	0.83	lb/hr	
NOx	0.96	lb/hr	
PM_{10}	2.25	lb/hr *	* Not modeled per WDEQ policy.
$PM_{2.5}$	0.27	lb/hr *	* Not modeled per WDEQ policy.

Long-Term Emission Rate: Exhaust and Unpaved Road Fugitives

E = EF * fHP + Unpaved Road Fugitive Emissions

CO ***	0.83	lb/hr
NOx ***	0.96	lb/hr
PM_{10}	1.75	lb/hr *
$PM_{2.5}$	0.22	lb/hr **

* PM_{10}: Futive portion (1.70 lb/hr) + exhaust portion (0.05 lb/hr).
** $PM_{2.5}$: Futive portion (0.17 lb/hr) + exhaust portion (0.05 lb/hr).
*** Conservatively assume same as short-term emission rate.

Emissions Per Volume for Modeling

Pollutant	Avg. Period	Emission Rate (lb/hr)	Emiss. Rate Per Volume (g/sec/vol.)
PM_{10}	Annual	1.75	2.2E-03
$PM_{2.5}$	Annual	0.22	2.8E-04
NOx	1-hour	0.96	1.2E-03
NOx	Annual	0.96	1.2E-03
CO	1-hr, 8-hr	0.83	1.1E-03

Source Characterization for Modeling *

DECA Truck

Height (H) =	12.1 ft	Top of Plume (TP) =	6.3	m	TP = 1.7*H
	3.7 m	Release height (RH) =	3.1	m	RH = TP/2
Width (W) =	10.7 ft	Sigma z (sz) =	2.91	m	Sz = TP/2.15
	3.3 m	Road Width (RW) =	9.1	m	Assumed 30 feet
		Volume Width (VW) =	15.1	m	VW = RW + 6m
		Sigma y (sy) =	7.04	m	Sz = (RW + 6)/2.15
		Volume Source Separation (VS) =	30.3	m	VS = VW*2
		Number Volumes Along One-way Segment =	99	vol. sources	

* Source: EPA Haul Road Workgroup:
http://www.epa.gov/scram001/reports/Haul_Road_Workgroup-Final_Report_Package-20120302.pdf

Conversion

453.6 grams per lb
1609.3 meters per mile

COAL ROAD EMISSION ESTIMATES FOR MODELING

Unpaved Roads PM_{10} Emission Factor			**Reference**
$EF = k * (s/12)^a * (W/3)^b$			AP-42, Section 13.2.2 (Revision 11/06), Page 13.2.2-4
k =	1.5	Constant	
s =	8.4 %	Silt content	Haul road, western surface coal mine (AP-42, Table 13.2.2-1)
a =	0.9	Constant	
W =	37.8 tons	Average Truck Weight	Solvay
b =	0.45	Constant	
EF =	3.40 lb/VMT		
CE * =	80 %	Minimum Control Efficiency (AP-42 estimate for chemical dust suppressants)	
EF' =	0.68 lb/VMT	Controlled Emission Factor	

* Per Solvay's permit, the coal road fugitive dust emissions are controlled with a minimum of bi-annual applications of chemical dust suppressants in conjunction with water applications sufficient to control fugitive dust.
The control efficiency here is based on AP-42, Chapter 13.2.2, Unpaved Roads. Figure 13.2.2-2 provides the control efficiencies achievable with watering (max of 95%) and AP-42 estimates a chemical dust suppressant control efficiency (application rate not specified) of at least 80%. Therefore, as a conservative estimate, the lower of the two maximum control efficiencies is used.

Unpaved Roads PM_{10} Emission Rate, E_{PM10}

$E_{PM10} = EF' * NT * RTD$

Where,
EF' = Controlled emission factor
NT = Number of trips
RTD = Round trip distance (miles)

Annual Number Trips		**Reference**
W_{load} =	39.5 tons/load	Solvay
NT_{annual} =	8,000 trips per year	Solvay - annual trips

Daily Number Trips

NT_{daily}=	24 trips/day	Solvay - max. daily trips

Round Trip Distance

RTD =	2.87 miles/trip	Estimated round trip distance for modeling.

Unpaved Road Particulate Emissions

Daily Emissions, PM_{10} ***		Daily Emissions, $PM_{2.5}$ **, ***	
E_{PM10} =	46.9 lb/day	$E_{PM2.5}$ =	4.7 lb/day
E_{PM10} =	1.95 lb/hr	$E_{PM2.5}$ =	0.20 lb/hr
Annual Emissions, PM_{10}		Annual Emissions, $PM_{2.5}$ **	
E_{PM10} =	7.8 tons/year	$E_{PM2.5}$ =	0.8 tons/year
	1.78 annualized lb/hr *		0.18 annualized lb/hr *

* Assuming 8,760 hours of operation per year.
** The emission factor calculations above are a linear function of the constant k. Per AP-42, Section 13.2.2, Table 13.2.2-2, k for $PM_{2.5}$ equals 0.15 and k for PM_{10} equals 1.5. Therefore, a $PM_{2.5}/PM_{10}$ mass fraction of 0.1 (i.e., 0.15/1.5) is applied to the PM_{10} emission rate to calculate a $PM_{2.5}$ emission rate for the haul road.
*** Per WDEQ policy, short-term fugitive particulate emissions are not modeled.

COAL ROAD EMISSION ESTIMATES FOR MODELING, CONTD.

Coal Road Exhaust Emissions

MOVES Heavy Duty Highway Exhaust Emission Factors, EFc

CO	0.0110	lb/mile
NO_X	0.0313	lb/mile
NO_2	0.0035	lb/mile
NO	0.0278	lb/mile
PM_{10}	0.0031	lb/mile
$PM_{2.5}$	0.0021	lb/mile

Reference

Vehicle ID: 62
Road Type: Rural Unrestricted
Road Speed: Solvay: 10 mph *

* Assumed speed of the trucks for MOVES; the MOVES emission factors at low speeds result in higher emission rates. Thus, these are conservative emission factor estimates, even when trucks travel at higher speeds. Per Solvay, these trucks typically travel around 10 mph.

Short Term Emission Rate: Exhaust Only *

E = EFc * NT_{daily} * RTD

CO	0.032	lb/hr
NO_X	0.090	lb/hr
NO_2	0.010	lb/hr
NO	0.080	lb/hr
PM_{10}	0.009	lb/hr
$PM_{2.5}$	0.006	lb/hr

* Assuming 1 trip per hour based on Solvay's total of 24 trips per day.

Short Term Emission Rate: Exhaust and Unpaved Road Fugitives

E = EFc * NT_{daily} * RTD + Unpaved Road Fugitive Emission:

CO	0.032	lb/hr	
NOx	0.090	lb/hr	
PM_{10}	1.96	lb/hr *	* Not modeled per WDEQ policy.
$PM_{2.5}$	0.20	lb/hr *	* Not modeled per WDEQ policy.

Long-Term Emission Rate: Exhaust and Unpaved Road Fugitives

E = EFc * NT_{daily} * RTD + Unpaved Road Fugitive Emissions

CO	0.032	lb/hr	Conservatively assume same as short-term emission rate.
NOx	0.090	lb/hr	Conservatively assume same as short-term emission rate.
PM_{10}	1.79	lb/hr *	Exhaust emissions portion are conservatively assumed as short-term emissions.
$PM_{2.5}$	0.18	lb/hr **	Exhaust emissions portion are conservatively assumed as short-term emissions.

NO_2/NOx Ratio
0.11

* PM_{10}: Futive portion (1.783 lb/hr) + exhaust portion (0.009 lb/hr).
** $PM_{2.5}$: Futive portion (0.18 lb/hr) + exhaust portion (0.006 lb/hr).

Emissions Per Volume for Modeling

Pollutant	Avg. Period	Emission Rate (lb/hr)	Emiss. Rate Per Volume (g/sec/vol.)
PM_{10}	Annual	1.79	2.6E-03
$PM_{2.5}$	Annual	0.18	2.7E-04
NOx	1-hour	0.09	1.3E-04
NOx	Annual	0.09	1.3E-04
CO	1-hr, 8-hr	0.03	4.6E-05

Source Characterization for Modeling *

Kenworth W900L Truck

Cab Height (CH) =	11.50 ft	Top of Plume (TP) =	6.0 m	TP = 1.7*CH
	3.51 m	Release height (RH) =	3.0 m	RH = TP/2
Stack Height (SH) =	15.00 ft	Sigma z (sz) =	2.77 m	Sz = TP/2.15
	4.57 m	Road Width (RW) =	7.32 m	RW = 24 feet
Width (W) =	8.50 ft	Volume Width (VW) =	13.3 m	VW = RW + 6m
		Sigma y (sy) =	6.19 m	Sy = (RW + 6m)/2.15
		Volume Source Separation (VS) =	26.6 m	VS = VW*2
		Number Volumes Along One-way Segment =	87 vol. sources	

* Source: EPA Haul Road Workgroup:
http://www.epa.gov/scram001/reports/Haul_Road_Workgroup-Final_Report_Package-20120302.pdf

RAILROAD EMISSIONS FOR MODELING

Engines	Number	Rating (hp)	Reference
EMD SD40-2	2	3,000	Solvay
EMD SD40T-2	1	3,000	Solvay

Operations:	16	hr/day	Solvay
	6	days/week	Solvay
	384	hr/month (4 weeks)	
	4,992	hr/yr	
Fuel use:	15,000	gal/month	Solvay
	39.1	gal/hr	

Conversion factor:	15.2 bhp-hr/gal	Source: Emission Factors for Locomotives; EPA-420-F-09-025, April 2009, Table 3.
Avg. power based on Solvay fuel use:	593.8 bhp	

Tier 0 Switch Emission Factors (g/bhp-hr)

PM_{10}	0.44
NOx	12.6
CO	1.83

Source: Emission Factors for Locomotives;
EPA-420-F-09-025, April 2009, Table 2.

Emissions for Entire Track Length (on and off property); 532 Volume Sources

	Short-term (lb/hr)	Emiss. Rate Per Volume (g/sec/vol.)
PM_{10}, $PM_{2.5}$	0.58	1.4E-04
NOx	16.49	3.9E-03
CO	2.40	5.7E-04

Track Within SIAs: Short-term Emission Rate for Modeling

Pollutant	SIA (km)	Volumes Within SIA	Emiss. Rate Per Volume (g/sec/vol.)
PM_{10}	3.9	302	1.4E-04
$PM_{2.5}$	5.0	339	1.4E-04
NOx	5.0	339	3.9E-03
CO	1.1	82	5.7E-04

Track Length:

Total Length of Track	15.8	km
Volumes Along Total Length	532	volumes

Conversions

453.6 grams per lb
3600 sec/hr

Track Within SIAs: Long-term Emission Rate for Modeling

Pollutant	SIA (km)	Volumes Within SIA	Emiss. Rate Per Volume (g/sec/vol.)
NOx	5.0	339	2.2E-03
PM_{10}	3.9	302	7.8E-05
$PM_{2.5}$	5.0	339	7.8E-05

Source Characteristics:

Engine Height (H)[1] =	4.8	meters	
Release Height (H)[2] =	7.13	meters	EH *1.5
Sigma z (sz) =	3.32	meters	Sz = RH/2.15
Width (W) =	8.04	meters	
Sigma y (sy) =	6.53	meters	Sy = (W + 6m)/2.15
Number Volumes Along Entire Lenth of Track =	532	vol. sources	

[1] Source: SD40-2 EMD Locomotive Specifications
http://www.highironillustrations.com/railfan_specification/spec_sd40.html
[2] Assume release height is 1.5 times the engine height to account for thermal and buoyant properties of exhaust.

Appendix J: Meteorological Data Preparation Analysis

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August 10, 2012

Project No. 170-12

Mr. James (Josh) Nall
NSR Program Principal
Wyoming Department of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

Subject: Meteorological Data for Air Quality Impact Modeling Analysis for Solvay Soda Ash Joint Venture Green River, Wyoming Facility – Natural Gas Boiler Project

Dear Mr. Nall:

The Solvay Soda Ash Joint Venture (Solvay) Green River, Wyoming facility proposes to install one 254 MMBtu/hr natural-gas-fired package boiler to provide steam/heat to the facility's production processes. This boiler project will trigger Prevention of Significant Deterioration (PSD) review for particulate matter (PM, PM_{10}, and $PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG).

Solvay provided an air quality impact modeling protocol (dated July 9, 2012) for Wyoming Department of Environmental Quality (WDEQ) review prior to the completion of an impact modeling analysis and submittal of a PSD permit application to WDEQ. Per WDEQ comments on the protocol, Solvay is submitting the attached letter for WDEQ review. This letter describes the processing of the meteorological data to be used in the air quality impact analysis of the facility. Electronic copies of the meteorological data files are provided with the attached CD for WDEQ review. Thanks in advance for your consideration.

Sincerely,

Tim Martin

Tim Martin
Senior Atmospheric Scientist
Air Sciences Inc.

1455 NW OVERTON STREET, SUITE 500
PORTLAND, OREGON 97209
503·525·9394 FAX 503·525·9412

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Meteorological Data

Three years (2009–2011) of on-site hourly surface meteorological data from Solvay's 30-meter tower were used as the basis for the meteorological data for this analysis. The coordinates of the on-site meteorological tower are approximately 41.504°N latitude and 109.767°W longitude. An aerial photograph showing the location of the on-site meteorological tower relative to the facility is provided in Figure 1. The primary land use surrounding the facility is characterized as shrub lands with a small fraction classified as grasslands. A three-year wind rose for the 10-meter wind data recorded at the meteorological tower is shown in Figure 2. Winds at the Solvay facility primarily blow from the west and west-northwest.

The 30-meter meteorological tower measures the following:

- 10-meter and 30-meter horizontal wind speed, direction, and standard deviation (sigma theta) with R.M. Young AQ wind sensors
- 10-meter and 30-meter vertical wind speed and standard deviation
- Ambient air temperature at 2, 10, and 30 meters with matching sensors for temperature difference with R.M. Young Platinum RTD Temperature Probes
- Precipitation with a Hydrological Services 8" Tipping Bucket
- Barometric pressure with a PTB 101B sensor
- Relative humidity with a Campbell Scientific HMP50 sensor
- Incoming solar radiation with a LI-COR LI-200SZ sensor

WDEQ approved the use of the LI-COR sensor for the on-site solar radiation measurements for this application in the initial modeling protocol.

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Figure 1. Aerial Photograph of On-site Meteorological Tower and Solvay Facility

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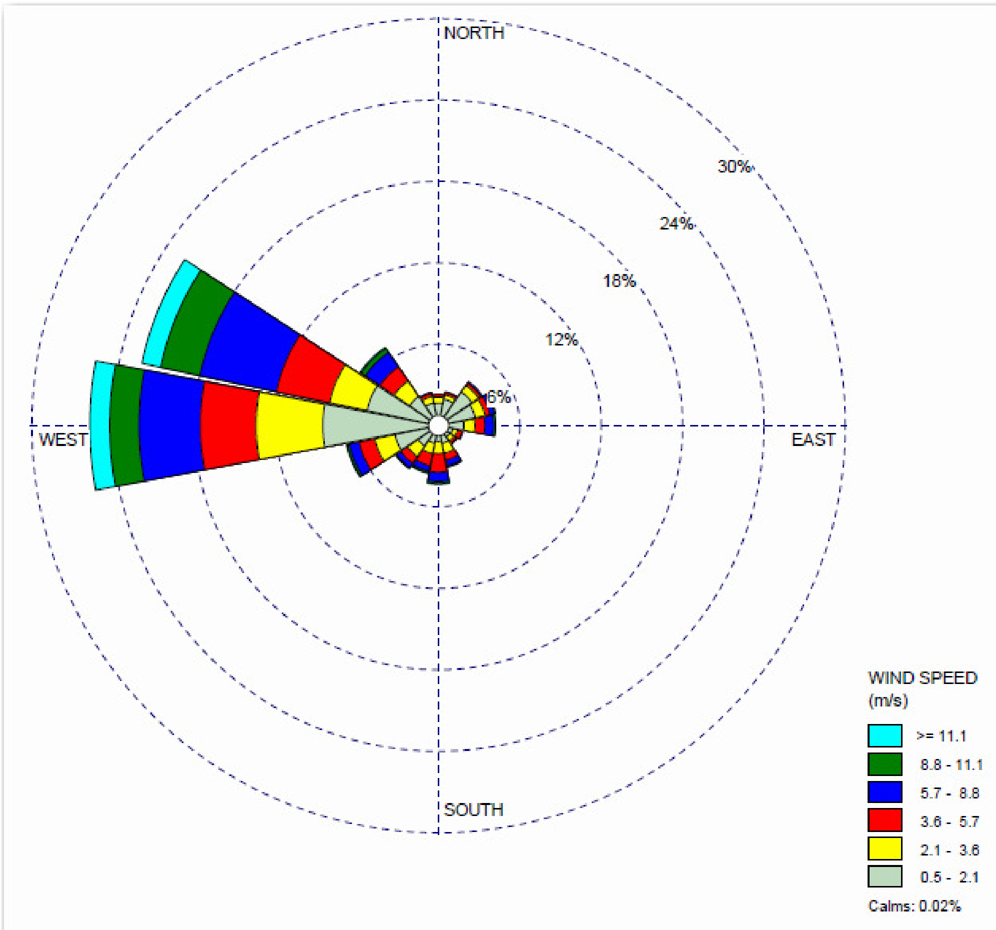
Figure 2. Three-year Wind Rose for Solvay's 10-meter On-site Wind Data



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Hourly and one-minute surface meteorological data from the Rock Springs Airport National Weather Service (NWS) station (WBAN# 24027, 41.60˚N, 109.07˚W) were used to provide cloud cover and fill in missing data as needed. The Rock Springs Airport is approximately 36 miles east of Solvay. The one-minute surface data were processed using the AERMINUTE processor (Version 11325).

Twice-daily upper-air data from the Riverton NWS station (WBAN# 24061; 43.06˚N, 108.47˚W) were also used. Radiosonde data from the Riverton NWS station were obtained from the National Oceanic & Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) Radiosonde Database (http://www.esrl.noaa.gov/raobs/). All levels of data are extracted from the database for use in AERMET.

AERMET requires the input of three surface boundary layer parameters: midday albedo, midday Bowen ratio, and surface roughness length. These parameters are dependent on the land use and vegetative cover of the area being evaluated. The AERSURFACE processor (version 08009) was used to estimate the surface parameters for this analysis. AERSURFACE requires the input of land cover data from the U.S. Geological Survey (USGS) National Land Cover Data 1992 archives (NLCD92), which it uses to determine the land cover types for the user-specified location. Each of the land cover categories in the NLCD92 archive is linked within AERSURFACE to a set of seasonal surface characteristics.

AERSURFACE was run for both the on-site tower location and for the NWS meteorological tower site. AERSURFACE was run with 12 sectors (30-degree increments starting at 0 degrees). Per WDEQ comments on the modeling protocol, WDEQ has generally assumed arid conditions for meteorological data sets in southwest Wyoming due to average annual precipitation totals that are below 9.0 inches per year. As shown in Table 1, the annual precipitation values for 2009 through 2011 at the Rock Springs station are all less than 9.0 inches per year. Thus, the surface moisture condition was characterized as "dry" and "arid" for all years in AERSURFACE.

Table 1. Precipitation Analysis – Rock Springs

Year	Rainfall (in)	Class
2009	8.06	DRY
2010	7.14	DRY
2011	8.70	DRY

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In addition, per WDEQ comments on the modeling protocol, WDEQ has generally assumed that continuous snow cover is not the typical condition in the vicinity of the Solvay facility during the winter and that the default seasonal breakdown in AERSURFACE is the most realistic representation for Wyoming. Solvay used these WDEQ recommendations in the AERSURFACE processing.

A one-kilometer radius for surface roughness calculation was used for this analysis. Four default seasonal periods were used:

- Midsummer with lush vegetation: June through August
- Autumn with unharvested cropland: September through November
- Late autumn after frost and harvest, or winter with no snow: December through February
- Transitional spring (partial green coverage, short annuals): March through May

The three years of on-site data, Rock Springs surface NWS data, and Riverton upper-air data were processed into AERMOD-ready files using the current version of AERMET (version 11059). The wind threshold was set to 0.5 m/s based on the reported wind vane threshold.[1] For the energy calculations, the bulk Richardson approach was utilized with the temperature difference (DT01) and solar radiation measurements.

For WDEQ review, electronic copies of the meteorological data files are provided with the attached CD.

[1] R.M. Young AQ Wind Monitor specifications: http://www.youngusa.com/products/7/6.html

Appendix K: Measured In-Stack NO_2/NO_x Data

CA 1-2 - Reference Method Data

	Nox	NO	NO2		% difference
R1	87.47	81.76	5.71		6.52%
R2	87.49	83.82	3.67		4.20%
				Average	**5.36%**

BO-1 - Reference Method Data

	Nox	NO	NO2	% difference
R4	305.73	288.40	17.33	5.67%
R5	315.21	296.95	18.26	5.79%
R6	308.45	285.97	22.48	7.29%
R7	305.86	283.18	22.68	7.41%
R8	309.05	286.91	22.14	7.16%
R9	304.23	281.65	22.58	7.42%
R10	303.39	280.37	23.02	7.59%
			Average	**6.90%**

BO-2 - Reference Method Data

	Nox	NO	NO2		% difference
R1	292.74	277.97	14.78		5.05%
R2	297.82	281.61	16.21		5.44%
R3	297.62	280.26	17.36		5.83%
R4	300.99	282.29	18.70		6.21%
R5	297.56	279.16	18.40		6.18%
R6	299.16	280.66	18.51		6.19%
R7	294.30	278.14	16.16		5.49%
R8	294.12	277.53	16.59		5.64%
R9	290.74	274.37	16.38		5.63%
				Average	**5.74%**

Run 1 Data Summary

Client: Solvay Chemical
Facility: Green River
Process/Source: DR-6
Project No.: 1201A
Date: 5/24/2012
Technician: Ed Dike
Location: Stack

	NOx	O2	CO2	NO
Bias Gas Value	50.00	11.89	12.00	50.00
Analyzer Readings				
Initial Bias - Zero	0.41	0.19	0.08	0.43
Initial Bias - span gas	48.27	11.69	11.79	49.12
Final Bias - Zero	1.11	0.17	0.05	0.76
Final Bias - span gas	48.70	11.66	11.70	47.98
Calculated Analyzer Bias (Allowable = 5%)				
Initial, zero gas	0.02 %	0.62 %	0.28 %	0.07 %
Initial, bias gas	1.48 %	0.94 %	0.98 %	1.22 %
Final, zero gas	0.68 %	0.53 %	0.16 %	0.40 %
Final, bias gas	1.05 %	1.07 %	1.34 %	2.36 %
Analyzer Drift (allowable = 3%)				
zero gas	0.70 %	0.08 %	0.12 %	0.33 %
bias gas	0.43 %	0.12 %	0.37 %	1.14 %
Results				
Start/Stop Time	10:00 to 10:56			
Run 1 Average (raw data)	39.81	14.10	3.64	39.69
Drift corrected average	**40.91**	**14.40**	**3.67**	**40.77**

NO_2	0.15

Run 2 Data Summary

Client: Solvay Chemical
Facility: Green River
Process/Source: DR-6
Project No.: 1201A
Date: 5/24/2012
Technician: Ed Dike
Location: Stack

	NOx	O2	CO2	NO
Bias Gas Value	50.00	11.89	12.00	50.00
Analyzer Readings				
Initial Bias - Zero	1.11	0.17	0.05	0.76
Initial Bias - span gas	48.70	11.66	11.70	47.98
Final Bias - Zero	0.57	0.15	0.05	0.83
Final Bias - span gas	48.32	11.67	11.68	49.51
Calculated Analyzer Bias (Allowable = 5%)				
Initial, zero gas	0.68 %	0.53 %	0.16 %	0.40 %
Initial, bias gas	1.05 %	1.07 %	1.34 %	2.36 %
Final, zero gas	0.14 %	0.45 %	0.16 %	0.47 %
Final, bias gas	1.43 %	1.03 %	1.42 %	0.83 %
Analyzer Drift (allowable = 3%)				
zero gas	0.54 %	0.08 %	0.00 %	0.07 %
bias gas	0.38 %	0.04 %	0.08 %	1.53 %
Results				
Start/Stop Time	11:45 to 12:01			
Run 2 Average (raw data)	40.58	14.06	3.67	40.24
Drift corrected average	**41.68**	**14.36**	**3.73**	**41.13**

NO_2	**0.55**

Run 3 Data Summary

Client: Solvay Chemical
Facility: Green River
Process/Source: DR-6
Project No.: 1201A
Date: 5/24/2012
Technician: Ed Dike
Location: Stack

	NOx	O2	CO2	NO
Bias Gas Value	50.00	11.89	12.00	50.00
Analyzer Readings				
Initial Bias - Zero	0.57	0.15	0.05	0.83
Initial Bias - span gas	48.32	11.67	11.68	49.51
Final Bias - Zero	1.46	0.15	0.05	0.68
Final Bias - span gas	49.30	11.67	11.65	49.82
Calculated Analyzer Bias (Allowable = 5%)				
Initial, zero gas	0.14 %	0.45 %	0.16 %	0.47 %
Initial, bias gas	1.43 %	1.03 %	1.42 %	0.83 %
Final, zero gas	1.03 %	0.57 %	0.16 %	0.32 %
Final, bias gas	0.45 %	1.03 %	1.55 %	0.52 %
Analyzer Drift (allowable = 3%)				
zero gas	0.89 %	0.00 %	0.00 %	0.15 %
bias gas	0.98 %	0.00 %	0.12 %	0.31 %
Results				
Start/Stop Time	14:28 to 15:29			
Run 3 Average (raw data)	41.31	14.22	3.61	41.62
Drift corrected average	**42.15**	**14.52**	**3.68**	**41.78**

NO_2	**0.37**

Appendix L: Class I Area FLAG Initial Criteria Screening Analysis

From: Josh Nall <josh.nall@wyo.gov>
Sent: Monday, May 14, 2012 8:24 AM
To: Kent Norville; Tim Martin
Subject: FW: Solvay PSD Project: Q/D document

Debbie Miller at the USFS has determined that an AQRV analysis is not needed for the Solvay PSD project (see below). Please let me know if you need more information. Thanks, Josh.

James (Josh) Nall
Natural Resources Program Supervisor
Wyoming Dept. of Environmental Quality – Air Quality Division
122 W. 25th Street
Cheyenne, WY 82002
(307) 777-7816

From: Miller, Debra C -FS [mailto:dcmiller@fs.fed.us]
Sent: Friday, May 11, 2012 2:23 PM
To: Josh Nall
Cc: Sorkin, Jeff A -FS
Subject: RE: Solvay PSD Project: Q/D document

Josh

Based upon the numbers you provided in the attached document, the Forest Service will not require a Class I AQRV analysis for this project.

Debbie

From: Josh Nall [mailto:josh.nall@wyo.gov]
Sent: Thursday, April 26, 2012 8:18 AM
To: Miller, Debra C -FS; Susan Johnson
Subject: Solvay PSD Project: Q/D document

Solvay Soda Ash is proposing a modification to their Green River, Wyoming facility that will trigger PSD. They are proposing to add a gas-fired boiler to add additional steam for production, and this will serve to debottleneck several other affected sources. They have provided a document (attached) with a project description and Q/D calculations. The calculated Q/D for the nearest Class I area (Bridger WA) is less than 10, and the "Q" is calculated conservatively using the full PTE emissions for each source rather than the net emissions increase (PTE minus actuals). Please let me know if you have any questions or require any additional information. We ask that you provide a determination on the need for Class I AQRV analyses for the proposed project. Thank you, Josh.

James (Josh) Nall
NSR Program Principal, Dispersion Modeling
Wyoming Dept. of Environmental Quality – Air Quality Division
122 W. 25th Street
Cheyenne, WY 82002
(307) 777-7816

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Act and may be disclosed to third parties.

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April 20, 2012

Project No. 170-12

Mr. James (Josh) Nall
NSR Program Principal
Wyoming Department of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

Subject: Class I Area FLAG Initial Screening Criteria Analysis for Solvay Soda Ash Joint Venture Green River, Wyoming Facility – New Boiler Project

Dear Mr. Nall:

The Solvay Soda Ash Joint Venture (Solvay) Green River, Wyoming facility proposes to install one 254 MMBtu/hr natural-gas-fired package boiler (new boiler) to provide steam/heat to the facility's production processes. This new boiler project will trigger Prevention of Significant Deterioration (PSD) review for particulate matter (PM, PM_{10}, and $PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG).

As discussed with the Wyoming Department of Environmental Quality (WDEQ) at a meeting on February 23, 2012, Solvay is providing the attached technical summary of a Class I Area FLAG Initial Screening Criteria analysis for its boiler project for WDEQ and Federal Land Manager (FLM) review prior to the submittal of an impact modeling protocol and PSD permit application to WDEQ. As discussed at the meeting, please provide this analysis to the appropriate FLMs for their review.

Under the FLAG Initial Screening Criteria methodology, agencies may consider an existing source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I Air Quality Related Values (AQRVs), including visibility, if its total annual sulfur dioxide (SO_2), NO_X, PM_{10}, and sulfuric acid (H_2SO_4) emissions in tons per year (Q) from the project modification, divided by the distance in km (D) from the Class I area, are less than 10. Based on the annual emissions from the project modification, the Q/D for the project will be less than 10

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for all nearby Class I areas. Thus, the project would have negligible impacts with respect to Class I AQRVs, including visibility, and Solvay would not be required to perform any further Class I AQRV analyses. With this letter, Solvay is requesting a determination of whether this is a sufficient demonstration of negligible impact on the surrounding Class I areas for this Solvay source modification.

Sincerely,

Kent Norville

Kent Norville, Ph.D.
Atmospheric Scientist
Air Sciences Inc.

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Class I FLAG Initial Screening Criteria Analysis for the Solvay New Boiler Project

Solvay Soda Ash Joint Venture (Solvay) proposes to install one 254 MMBtu/hr natural-gas-fired package boiler (new boiler) to provide steam/heat to the Green River, Wyoming facility's production processes and for other purposes, such as building heat. Currently, steam/heat is provided to the facility by two coal-fired boilers (Sources #18 and #19), which are routinely shut down for maintenance and thus are not operated at full annual capacity. As a result, production at the facility is also limited (i.e., bottlenecked) when steam is not available from the existing boilers to support production processes. With the addition of the new gas-fired boiler, additional steam will be available to the facility to supplement or replace steam from the existing boilers when they are not operating. As a result, several sources will be debottlenecked, allowing an increase in annual production at the facility. None of the short-term (hourly and 24-hour) process source capacities will change with this boiler addition.

The sum of the emissions changes from the new boiler, associated debottlenecked sources, and creditable contemporaneous emissions increases and decreases results in a significant net emissions increase of particulate matter (PM, PM_{10}, and $PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG), thus triggering Prevention of Significant Deterioration (PSD) review. This report provides a preliminary summary of the Class I area screening procedure, as outlined in the Federal Land Managers' (FLM) Air Quality Related Values (AQRV) Work Group (FLAG) Phase I Report—Revised (2010).[1]

The Solvay facility is located in Section 31, T18N, R109W, approximately 20 miles west of the town of Green River, in Sweetwater County, Wyoming, as shown in Figure 1. The facility is located at 41.502˚N latitude and 109.757˚W longitude, which corresponds to 603.7 km Easting and 4,594.8 km Northing (zone 12) in the Universal Transverse Mercator (UTM) 1927 North American Datum (NAD27) system. Figure 2 shows a view of the facility.

[1] Natural Resource Report NPS/NRPC/NRR—2010/232; http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

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Figure 1. Solvay Facility Location on a Regional Scale Map

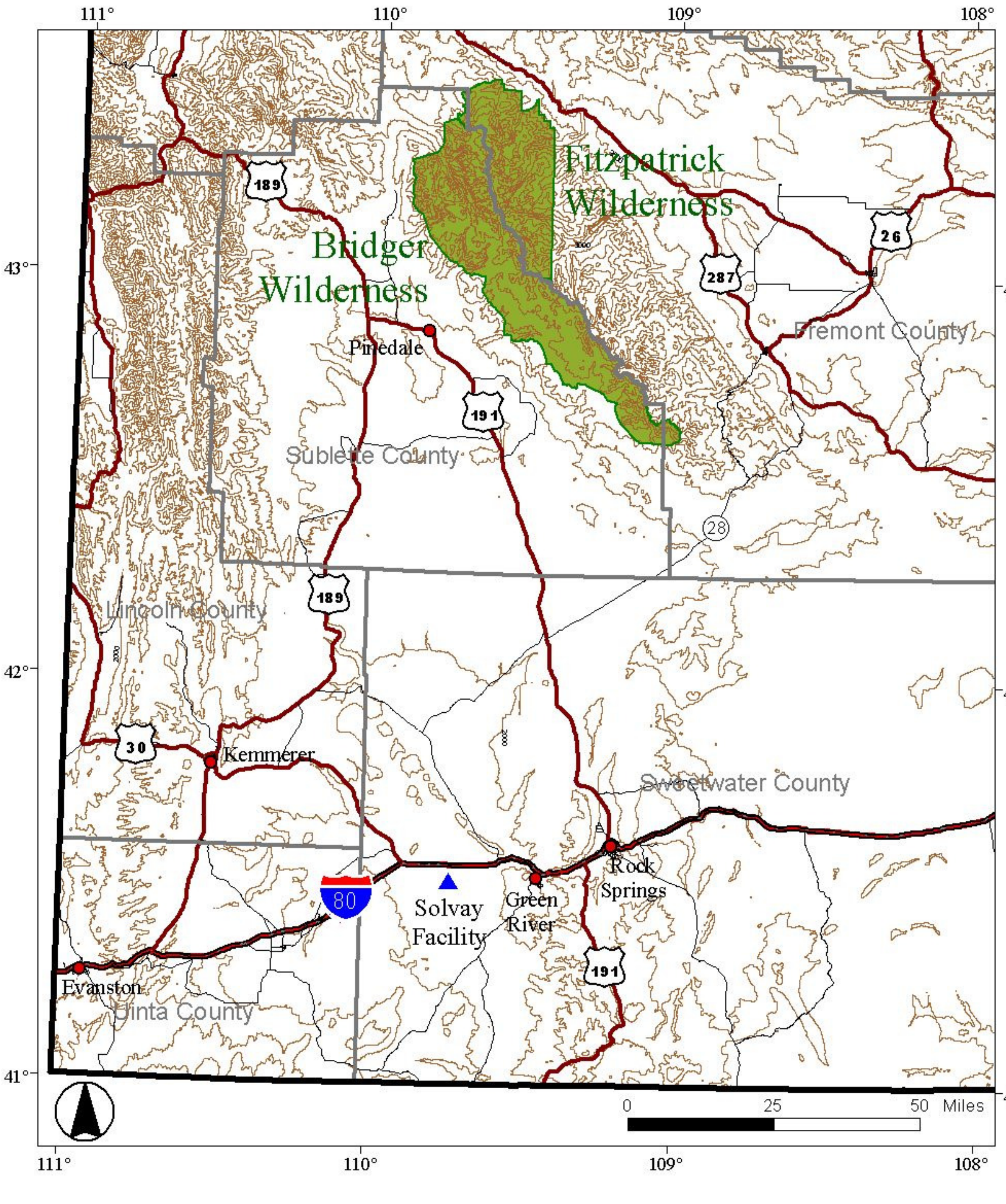

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Figure 2. View of Solvay Facility

FLAG Initial Screening Criteria Methodology

Under the FLAG Initial Screening Criteria methodology, agencies will consider an existing source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs, including visibility, if its total annual sulfur dioxide (SO_2), NO_X, PM_{10}, and sulfuric acid (H_2SO_4) emissions in tons per year (Q) from the project modification, divided by the distance in km (D) from the Class I area, are less than 10. The total emissions from the modification must be based on the maximum allowable 24-hour emission rates, assuming continuous (e.g., 365 days/year) operation.

Figure 3 shows the location of the Class I areas with respect to the Solvay facility. All Class I areas are located greater than 50 kilometers (km) from the Solvay facility. Although it is not one of the 156 Federal Class I areas, the State of Wyoming has declared that the Savage Run Wilderness area must be managed as a Class I area; therefore, this wilderness area was also included in the Class I area screening analysis.

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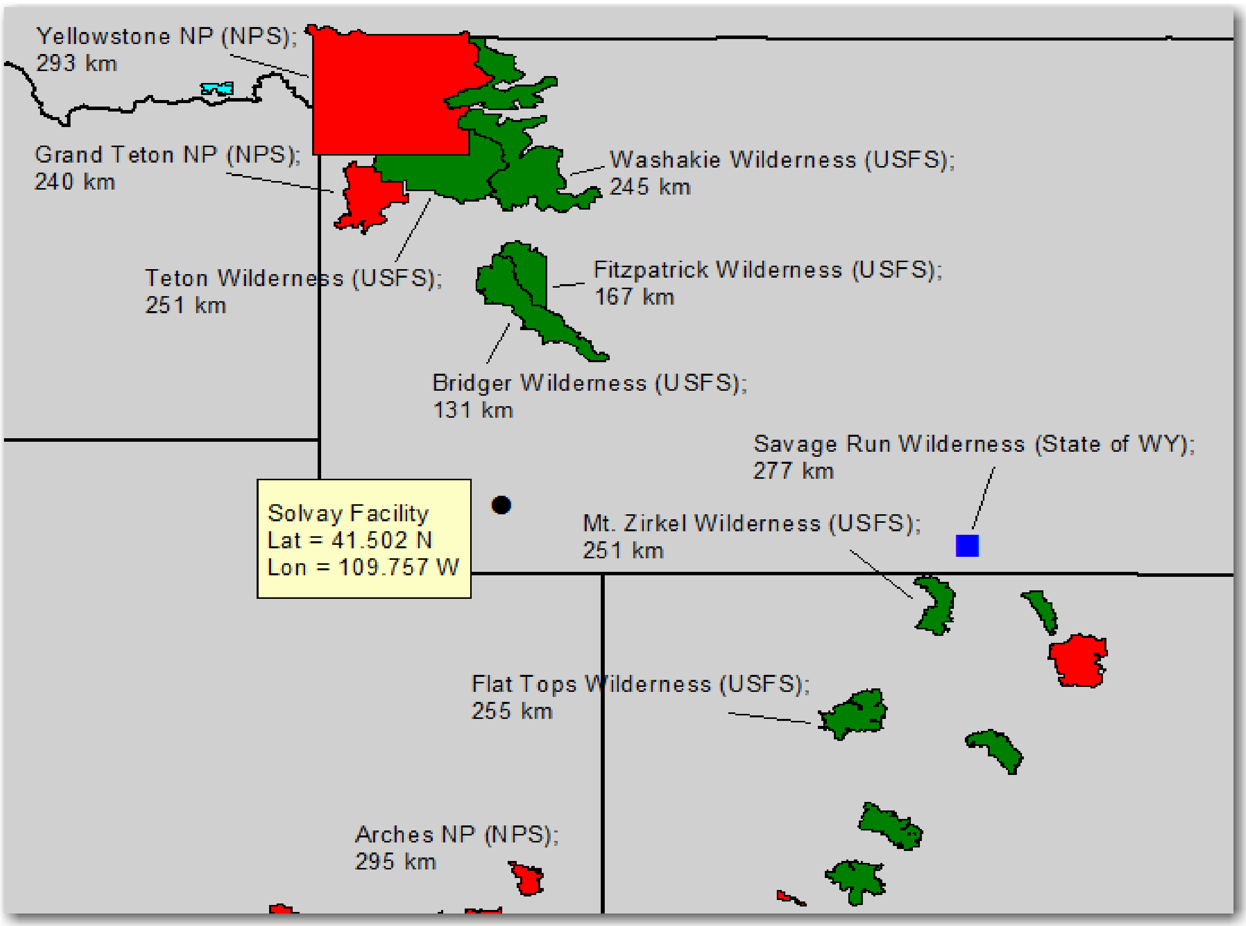
Figure 3. Location of Class I Areas within 300 Kilometers of the Solvay Facility



Project Emissions

Table 1 shows the anticipated project emissions. These estimates are conservative because the emissions for the new package boiler are based on existing emission rates, which have not taken into account Best Available Control Technology (BACT) limits. Annual emission rates are based on the maximum hourly rate applied over the entire year (8,760 hours/year). Emissions of H_2SO_4 from the project are insignificant and are not considered further.

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Table 1. Solvay Boiler Project Anticipated Emission Rates for PM_{10}, SO_2, and NO_X

WDEQ Source ID	Source Description	Maximum Allowable Emissions					
		PM_{10}		SO_2		NO_X	
		(lb/hr)	(TPY)	(lb/hr)	(TPY)	(lb/hr)	(TPY)
---	New Package Boiler*	1.89	8.3	0.15	0.7	9.65	42.3
02A	Ore Crusher Building #1	1.60	7.0	---	---	---	---
06A	Product Silos - Top	0.30	1.3	---	---	---	---
06B	Product Silos - Bottom #1	0.51	2.2	---	---	---	---
07	Product Loadout Station	1.20	5.3	---	---	---	---
15	DR-1 & 2 Steam Tube Dryers	3.00	13.1	---	---	1.80	7.9
16	Dryer Area	0.90	3.9	---	---	---	---
17	"A" and "B" Calciners	30.00	131.4	1.00	4.4	116.00	508.1
46	Ore Transfer Station	0.71	3.1	---	---	---	---
48	"C" Calciner	8.00	35.0	---	---	15.00	65.7
50	"C" Train Dryer Area	0.70	3.1	---	---	---	---
51	Product Dryer #5	2.40	10.5	---	---	18.00	78.8
52	Product Silos - Top #2	0.50	2.2	---	---	---	---
53	Product Silos - Bottom #2	0.45	2.0	---	---	---	---
76	"D" Train Primary Ore Screening	2.45	10.7	---	---	---	---
79	Ore Transfer Point	0.84	3.7	---	---	---	---
80	"D" Ore Calciner	10.00	43.8	---	---	20.00	87.6
81	"D" Train Dryer Area	0.50	2.2	---	---	---	---
82	DR-6 Product Dryer	3.45	15.1	---	---	30.00	131.4
99	Crusher Baghouse #2	3.20	14.0	---	---	---	---
100	Calciner Coal Bunker	0.20	0.9	---	---	---	---
103	East Ore Reclaim Baghouse	0.33	1.4	---	---	---	---
104	West Ore Reclaim Baghouse	0.27	1.2	---	---	---	---
	Totals >	---	321.5	---	5.0	---	921.8

* Conservative value based on existing emission rate, which does not incorporate BACT limits.
TPY rates based on maximum hourly rate applied over the entire year (8,760 hours per year).

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Results

Based on the emission rates from Table 1, the sum of the maximum annual PM_{10}, SO_2, and NO_X emission rates is 1,248 TPY. Table 2 shows the Q/D calculations for all Class I areas within 300 km of Solvay. At all Class I areas, the Q/D is less than 10; thus, the Solvay project will have negligible impacts on visibility and other AQRVs, and Solvay is not required to perform any further Class I AQRV analyses. Note that the Class I PSD increments will still need to be evaluated for the project.

Table 2. Q/D Calculations for Class I Areas within 300 Kilometers of Solvay

Class I Area	Agency	D (km)	Q/D	Less than 10?
Bridger Wilderness	USFS	131	9.5	Yes
Fitzpatrick Wilderness	USFS	167	7.5	Yes
Grand Teton NP	NPS	240	5.2	Yes
Washakie Wilderness	USFS	245	5.1	Yes
Teton Wilderness	USFS	251	5.0	Yes
Mt. Zirkel Wilderness	USFS	251	5.0	Yes
Flat Tops Wilderness	USFS	255	4.9	Yes
Savage Run Wilderness	WY	277	4.5	Yes
Yellowstone NP	NPS	293	4.3	Yes
Arches NP	NPS	295	4.2	Yes

Appendix M: Emission Calculations for Health Risk Assessment

PACKAGE BOILER AND DEBOTTLENECKED SOURCES: TOXIC EMISSION FACTORS AND INPUTS AND TOXICITY INFORMATION

Pollutant	Reference	Gas EF ($lb/10^6$ scf)	Gas EF (lb/MMBtu) *	Coal EF (lb/ton)	Dose Response Risk Factor Chronic Cancer - Inhalation ($1/\mu g/m^3$) **
Acetaldehyde	ACE	---	---	5.7E-04	0.0000022
Arsenic	ARS	2.00E-04	1.96E-07	4.1E-04	0.0043
Benzene	BZN	2.10E-03	2.06E-06	1.3E-03	0.0000078
Benzo(a)anthracene	BZA	1.80E-06	1.76E-09	8.0E-08	0.00011
Benzo(a)pyrene	BZP	1.20E-06	1.18E-09	3.8E-08	0.0011
Benzo(b)fluoranthene	BBF	1.80E-06	1.76E-09	---	0.00011
Benzo(k)fluoranthene	BZF	1.80E-06	1.76E-09	---	0.00011
Benzyl chloride	BZC	---	---	7.0E-04	0.000049
Beryllium	BER	1.20E-05	1.18E-08	2.1E-05	0.0024
Bis(2-ethylhexyl)phthalate	BIS	---	---	7.3E-05	0.0000024
Bromoform	BRO	---	---	3.9E-05	0.0000011
Cadmium	CAD	1.10E-03	1.08E-06	5.1E-05	0.0018
Chromium (VI)	CVI	---	---	7.9E-05	0.012
Chrysene	CHR	1.80E-06	1.76E-09	1.0E-07	0.000011
Dibenzo(a,h)anthracene	DIB	1.20E-06	1.18E-09	---	0.0012
2,4-Dinitrotoluene	DIN	---	---	2.8E-07	0.000089
7,12-Dimethylbenz(a)anthracene	DIM	1.60E-05	1.57E-08	---	0.071
Ethyl benzene	ETB	---	---	9.4E-05	0.0000025
Ethylene dibromide	EDB	---	---	1.2E-06	0.0006
Ethylene dichloride	EDC	---	---	4.0E-05	0.000026
Formaldehyde	FRM	7.50E-02	7.35E-05	2.4E-04	0.000013
Hexachlorodibenzo-p-dioxin, mixture	HEX	---	---	2.87E-11	1.3
Indeno(1,2,3-cd)pyrene	IND	1.80E-06	1.76E-09	6.1E-08	0.00011
Methyl tert-butyl ether	MTB	---	---	3.5E-05	2.6E-07
Methylene chloride	MCH	---	---	2.9E-04	1E-08
Naphthalene	NAP	6.10E-04	5.98E-07	1.3E-05	0.000034
2,3,7,8-Tetrachlorodibenzo-p-dioxin	TET	---	---	1.43E-11	33

Gas emission factors from AP-42, Section 1.4 - "Natural Gas Combustion," Tables 1.4.3 and 1.4-4 (Revision 7/98).
* Per AP-42, Section 1.4, Table 1.4-2, to convert the AP-42 emission factors in lb/MMscf to lb/MMBtu divide by 1020.

Coal emission factors from AP-42, Section 1.1 - "Bituminous and Subbituminous Coal Combustion," Tables 1.1-12, -13, -14, -18 (Revision 9/98).
Solvay coal emissions based on controlled combustion (ESP).

** EPA Air Toxics Website:
http://www.epa.gov/ttn/atw/toxsource/summary.html

Assumptions			Reference
Coal thermal equivalent	10,000	Btu/lb	Solvay
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)

Conversions		
	453.59	g/lb
	2000	lb/ton
	2.20462	lb/kg
	8760	hr/yr
	3600	sec/hr
	453.6	g/lb

Blue are input values and black are calculated values.

PACKAGE BOILER AND DEBOTTLENECKED SOURCES: MAXIMUM THROUGHPUTS/RATINGS

WDEQ Source ID	Source Description	Fuel	Hours	Max. Rating (MMBtu/hr)	Coal Usage (tons/yr)	Coal Usage (MMBtu/yr)	Gas Usage (MMBtu/yr)
---	New Package Boiler	Gas	8760	254	---	---	2,225,040
15	DR-1 & 2 Steam Tube Dryers	None*	---	---	---	---	---
17	"A" and "B" Calciners	Coal	8760	400	175,200	3,504,000	---
48	"C" Calciner	Gas	8760	250	---	---	2,190,000
51	Product Dryer #5	Gas	8760	150	---	---	1,314,000
80	"D" Calciner	Gas	8760	400	---	---	3,504,000
82	DR-6 Product Dryer	Gas	8760	200	---	---	1,752,000

* Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used; Solvay wishes to remove these preheaters and eliminate them from the facility's air permit.

PACKAGE BOILER AND DEBOTTLENECKED SOURCES: TOXIC EMISSION CALCULATIONS

		Annual PTE (tpy)						
Pollutant	**Reference**	**Boiler**	**#17**	**#48**	**#51**	**#80**	**#82**	**Total**
Acetaldehyde	ACE	---	5.0E-02	---	---	---	---	4.99E-02
Arsenic	ARS	2.18E-04	3.6E-02	2.1E-04	1.3E-04	3.4E-04	1.7E-04	3.70E-02
Benzene	BZN	2.29E-03	1.1E-01	2.3E-03	1.4E-03	3.6E-03	1.8E-03	1.25E-01
Benzo(a)anthracene	BZA	1.96E-06	7.0E-06	1.9E-06	1.2E-06	3.1E-06	1.5E-06	1.67E-05
Benzo(a)pyrene	BZP	1.31E-06	3.3E-06	1.3E-06	7.7E-07	2.1E-06	1.0E-06	9.79E-06
Benzo(b)fluoranthene	BBF	1.96E-06	---	1.9E-06	1.2E-06	3.1E-06	1.5E-06	9.69E-06
Benzo(k)fluoranthene	BZF	1.96E-06	---	1.9E-06	1.2E-06	3.1E-06	1.5E-06	9.69E-06
Benzyl chloride	BZC	---	6.1E-02	---	---	---	---	6.13E-02
Beryllium	BER	1.31E-05	1.8E-03	1.3E-05	7.7E-06	2.1E-05	1.0E-05	1.90E-03
Bis(2-ethylhexyl)phthalate	BIS	---	6.4E-03	---	---	---	---	6.39E-03
Bromoform	BRO	---	3.4E-03	---	---	---	---	3.42E-03
Cadmium	CAD	1.20E-03	4.5E-03	1.2E-03	7.1E-04	1.9E-03	9.4E-04	1.04E-02
Chromium (VI)	CVI	---	6.9E-03	---	---	---	---	6.92E-03
Chrysene	CHR	1.96E-06	8.8E-06	1.9E-06	1.2E-06	3.1E-06	1.5E-06	1.85E-05
Dibenzo(a,h)anthracene	DIB	1.31E-06	---	1.3E-06	7.7E-07	2.1E-06	1.0E-06	6.46E-06
2,4-Dinitrotoluene	DIN	---	2.5E-05	---	---	---	---	2.45E-05
7,12-Dimethylbenz(a)anthracene	DIM	1.75E-05	---	1.7E-05	1.0E-05	2.7E-05	1.4E-05	8.62E-05
Ethylbenzene	ETB	---	8.2E-03	---	---	---	---	8.23E-03
Ethylene dibromide	EDB	---	1.1E-04	---	---	---	---	1.05E-04
Ethylene dichloride	EDC	---	3.5E-03	---	---	---	---	3.50E-03
Formaldehyde	FRM	8.18E-02	2.1E-02	8.1E-02	4.8E-02	1.3E-01	6.4E-02	4.25E-01
Hexachlorodibenzo-p-dioxin, mixture	HEX	---	2.5E-09	---	---	---	---	2.51E-09
Indeno(1,2,3-cd)pyrene	IND	1.96E-06	5.3E-06	1.9E-06	1.2E-06	3.1E-06	1.5E-06	1.50E-05
Methyl tert-butyl ether	MTB	---	3.1E-03	---	---	---	---	3.07E-03
Methylene chloride	MCH	---	2.5E-02	---	---	---	---	2.54E-02
Naphthalene	NAP	6.65E-04	1.1E-03	6.5E-04	3.9E-04	1.0E-03	5.2E-04	4.42E-03
2,3,7,8-Tetrachlorodibenzo-p-dioxin	TET	---	1.3E-09	---	---	---	---	1.25E-09

PACKAGE BOILER AND DEBOTTLENECKED SOURCES: TOXICITY-WEIGHTED SCREENING FOR CARCINOGENIC HAPS

Pollutant	Reference	X = Total Emissions (tpy)	Y = Dose Response Risk Factor (1/μg/m^3) **	X * Y	Percent of Total (X * Y)	Cumulative (%)
Arsenic	ARS	3.70E-02	0.0043	1.59E-04	56.5%	56.5%
Chromium (VI)	CVI	6.92E-03	0.012	8.30E-05	29.5%	86.0%
Cadmium	CAD	1.04E-02	0.0018	1.87E-05	6.6%	92.6%
7,12-Dimethylbenz(a)anthracene	DIM	8.62E-05	0.071	6.12E-06	2.2%	94.8%
Formaldehyde	FRM	4.25E-01	0.000013	5.52E-06	2.0%	96.8%
Beryllium	BER	1.90E-03	0.0024	4.57E-06	1.6%	98.4%
Benzyl chloride	BZC	6.13E-02	0.000049	3.00E-06	1.1%	99.5%
Benzene	BZN	1.25E-01	0.0000078	9.76E-07	0.3%	99.8%
Naphthalene	NAP	4.42E-03	0.000034	1.50E-07	0.1%	99.9%
Acetaldehyde	ACE	4.99E-02	0.0000022	1.10E-07	0.04%	99.9%
Ethylene dichloride	EDC	3.50E-03	0.000026	9.11E-08	0.03%	99.9%
Ethylene dibromide	EDB	1.05E-04	0.0006	6.31E-08	0.02%	99.96%
2,3,7,8-Tetrachlorodibenzo-p-dioxin	TET	1.25E-09	33	4.13E-08	0.01%	99.97%
Ethylbenzene	ETB	8.23E-03	0.0000025	2.06E-08	0.01%	99.98%
Bis(2-ethylhexyl)phthalate	BIS	6.39E-03	0.0000024	1.53E-08	0.01%	99.99%
Benzo(a)pyrene	BZP	9.79E-06	0.0011	1.08E-08	0.004%	99.99%
Dibenzo(a,h)anthracene	DIB	6.46E-06	0.0012	7.75E-09	0.003%	99.99%
Bromoform	BRO	3.42E-03	0.0000011	3.76E-09	0.001%	99.996%
Hexachlorodibenzo-p-dioxin, mixture	HEX	2.51E-09	1.3	3.27E-09	0.001%	99.997%
2,4-Dinitrotoluene	DIN	2.45E-05	0.000089	2.18E-09	0.001%	99.998%
Benzo(a)anthracene	BZA	1.67E-05	0.00011	1.84E-09	0.001%	99.998%
Indeno(1,2,3-cd)pyrene	IND	1.50E-05	0.00011	1.65E-09	0.001%	99.999%
Benzo(b)fluoranthene	BBF	9.69E-06	0.00011	1.07E-09	0.0004%	99.999%
Benzo(k)fluoranthene	BZF	9.69E-06	0.00011	1.07E-09	0.0004%	99.9996%
Methyl tert-butyl ether	MTB	3.07E-03	2.6E-07	7.97E-10	0.0003%	99.9998%
Methylene chloride	MCH	2.54E-02	1E-08	2.54E-10	0.0001%	99.9999%
Chrysene	CHR	1.85E-05	0.000011	2.03E-10	0.0001%	100%

** EPA Air Toxics Website:
http://www.epa.gov/ttn/atw/toxsource/summary.html

PACKAGE BOILER AND DEBOTTLENECKED SOURCES: TOXIC EMISSION CALCULATIONS FOR MODELED HAPs

		Annual Emissions (g/sec)					
Pollutant	**Reference**	**Boiler (#109)**	**#17**	**#48**	**#51**	**#80**	**#82**
Arsenic	ARS	6.28E-06	1.03E-03	6.18E-06	3.71E-06	9.88E-06	4.94E-06
Chromium (VI)	CVI	---	1.99E-04	---	---	---	---
Cadmium	CAD	3.45E-05	1.29E-04	3.40E-05	2.04E-05	5.44E-05	2.72E-05
7,12-Dimethylbenz(a)anthracene	DIM	5.02E-07	---	4.94E-07	2.96E-07	7.91E-07	3.95E-07
Formaldehyde	FRM	2.35E-03	6.05E-04	2.32E-03	1.39E-03	3.71E-03	1.85E-03
Beryllium	BER	3.77E-07	5.29E-05	3.71E-07	2.22E-07	5.93E-07	2.96E-07